

Public Interest Energy Research (PIER) Program FINAL PROJECT REPORT

NORTHERN CALIFORNIA REGIONAL INTEGRATION OF RENEWABLES

Prepared for: California Energy Commission
Prepared by: Pacific Gas and Electric Company and BEW Engineering, Inc. with
guidance from the Core Analysis Team



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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Northern California Regional Integration of Renewables is the final report for the Regional Integration of Renewables-Northern California Transmission Integration project (Contract Number 500-06-037, conducted by the Pacific Gas and Electric Company. The information from this project contributes to PIER's Renewable Energy Technologies Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-327-1551.

ABSTRACT

Access to the transmission grid is a major challenge for large-scale deployment of renewable resources. A number of federal and state renewable integration studies focused on improving and refining resource information for new renewable developments. Although useful, these resource-focused, economic assessments are still too speculative for utility transmission planning needs. While ongoing discussions of the various potential resources development scenarios are necessary, utility transmission planners are faced with the challenge of balancing cost, maintaining reliability, and planning for an optimal blend of generating resources to meet load before project-specific resource information is available. To meet Renewables Portfolio Standard targets and the necessary grid reinforcements to support such targets, a more proactive approach is urgently needed to accelerate and provide information to, but not degrade, the highly regulated planning process.

The California Energy Commission's Public Interest Energy Research (PIER) Program funded the Regional Integration of Renewables project, which was developed together with renewable industry stakeholders and utility planners. This project focuses on the Northern California region to develop a proactive alternative to assess long-lead time transmission expansion needs in light of new resource opportunities. Information and an innovative proactive approach enables utilities to coordinate planning and consider options much earlier than the traditional process. This paper outlines the Regional Integration of Renewables project proactive transmission planning approach and analysis methods. Study highlights, preliminary renewable resource scenarios, and "least-regrets" transmission options are also identified and discussed.

Keywords: California Energy Commission, Northern California Regional Integration of Renewables, RIR, transmission planning, resource scenarios, renewables integration, Pacific Gas and Electric Company

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EXECUTIVE SUMMARY

For reliability, environmental, and economic reasons, transmission owners hesitate to invest speculatively in transmission infrastructure on a “build it and they will come” approach. At the same time, generation developers are not necessarily aware of the “cans” and “cannot” placed on highly regulated transmission owners/planners; nor do generation developers want to pay the full price tag for new transmission simply because they might be the first in a series of generators in commercial operation. To address this issue and bridge the gap between transmission owners and renewable generation project developers, the California Energy Commission funded, and the Pacific Gas and Electric Company executed the Regional Integration of Renewables Project. The project identifies common bulk transmission system upgrades (230 kilovolt to 500 kilovolt) that are likely to be needed in Northern California as mandated renewable generation resources are added to the system. The project team identifies those upgrades that show the best combination of system benefits and insensitivity to actual location of the renewable generator as “least regrets” upgrade opportunities.

This information provides utilities, transmission owners, and state and federal agencies insight on “least regrets” infrastructure improvements necessary to meet the mandated renewable energy requirements. The transmission options include a list of high voltage transmission line upgrades and expansions that require multiagency coordination and lead time to study, approve, permit, and construct. As such, the “least regrets” transmission recommendations presented here do not cover every transmission requirement down to the local subtransmission level. Localized transmission to connect specific renewable projects to the grid or lower voltage upgrades still require detailed studies by the responsible utility on an individual project basis.

This technical effort was tailored to build on the data and recommendations from the California Energy Commission’s Intermittency Analysis Project and the Strategic Value Analysis Project, which are statewide renewable resource studies. Those projects, along with other renewable integration efforts conducted by the California Independent System Operator (California ISO), the California Public Utilities Commission (CPUC), and the California Energy Commission, support the state’s Renewables Portfolio Standard mandates, climate policies and other energy directives. Staffs from the state agencies, publicly owned utilities, and investor-owned utilities have served as technical advisors with renewable industry stakeholders on many of the Public Interest Energy Research (PIER) Program renewables integration studies. Comprehensive studies, such as the Intermittency Analysis Project, have used a proactive and collaborative approach to conceptually planned transmission upgrades, and expansions in anticipation of renewable resource development. This approach should reduce some of the risks for utilities and their customers and accelerate communication and planning efforts to prioritize early transmission investment needs.

Near the completion of the Intermittency Analysis Project effort in June of 2007, Pacific Gas and Electric Company, along with PIER and the entities registered at the North American Electric Reliability Corporation as Transmission Planners and Transmission Operators in Northern California, organized the Regional Integration of Renewables Project for Northern California.¹ Technical in nature, the Regional Integration of Renewables Project focused on developing a set of “least-regrets” transmission projects in Northern California that supports development of a diverse set of scenarios of portfolios of renewable energy generation technologies, including wind, geothermal, biomass, and solar. The project analysis provides the regional utilities’ perspective on common areas for transmission upgrades and expansions, and encourages collaborative development to achieve common policy goals.

The method focused on investigating a reasonably large number of possible future renewable resource development scenarios and assumed that different combinations of technologies and locations could meet the same renewable policy goals. Each renewable development scenario produces approximately the same amount of renewable energy annually. Because each scenario assumes different technologies at different locations, the same energy level corresponds to different installed generation capacities at various locations with different amounts of generation on-line at various times.

Each renewable scenario results in different impacts on the transmission system, overloading certain transmission facilities at various times. In the analysis, the research team recorded the number of incidences of transmission facility overloading. For each renewable resource development scenario, the research team evaluated a number of transmission options (each consisting of a number of conceptual transmission projects) for their potential to reduce or eliminate the various potential overloads. Then, the project team ranked the hypothetical transmission projects based on their effectiveness in reducing or eliminating the largest number of overloads.

This method enables:

- Identification of common transmission needs, as diverse renewable resources are considered for the region.
- Foresight to consider transmission development and investment options in advance of site-specific generation resource proposals.
- Proactive exploration of transmission constraints outside the conventional transmission planning paradigm.

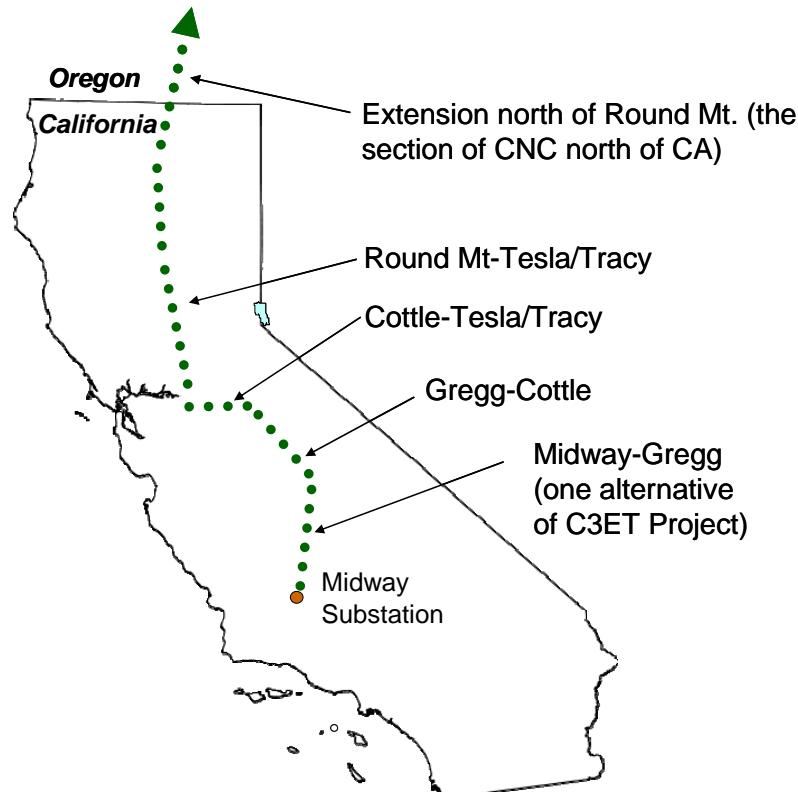
¹ Please see NERC Functional Model for description of Transmission Planner and Transmission Operator (http://www.nerc.com/files/Functional_Model_V4_CLEAN_2008Dec01.pdf)

- Application of consistent reliability-based transmission metrics in developing the best system configuration options, priorities, and system upgrade requirements needed to anticipate and attain reliable performance with high renewable penetration.

This paper summarizes the Regional Integration of Renewables Project effort. Sections below provide an overview of the project method and approach in creating the Northern California conceptual transmission plans. The plans are based on 10 resource scenarios and 3 different system conditions for each scenario, including renewable resource scenarios presented to stakeholders for feedback, refinement of the renewable resource scenarios, and development of 12 transmission options for each resource scenario (including the status quo transmission option). This activity has produced a conceptual transmission plan for Northern California and recommendation for next steps.

The simplified map in Figure 1 below shows those transmission projects that supported the widest variety of renewable development scenarios. These may be considered the “least regrets” infrastructure improvements in Northern California identified in the Renewable Integration of Renewables project.

Figure 1: Simplified Transmission Project Map



Source: RIR

Background

In 2002, the California Energy Commission (Energy Commission) recognized the need for transmission integration studies to facilitate transmission development as higher penetrations of renewable resources are added to meet Renewable Resource Portfolio Standards. The Energy Commission's Public Interest Energy Research Program funded projects to investigate transmission integration issues. The PIER-funded projects, in which BEW Engineering participated to date, include:²

- Strategic Value Analysis.
- Intermittency Analysis Project.
- Northern California Regional Integration of Renewables.
- Locational Value of Combined Heat and Power Resources.

The transmission grid integration issues are best represented as a big puzzle as shown below in Figure 2: Transmission Grid Integration Puzzle

Each renewable technology study adds another piece to the puzzle of solving the transmission grid expansion and access by renewable developers. The Regional Integration of Renewables study does not complete the puzzle but adds a major addition toward determining needed transmission expansion. The last piece to complete the puzzle would require individual utilities and regulatory agencies to follow up and validate the necessary transmission needs.

Figure 2: Transmission Grid Integration Puzzle



Source: RIR

2 Sections of this report and some reference material may mention Ron Davis of Davis Power Consultants. In July 2008, Davis Power Consultants (DPC) and BEW Engineering (BEW) merged. This report refers to Ron Davis of BEW Engineering.

BEW Engineering participated in the Strategic Value Analysis Study for PIER. The first objective of the Strategic Value Analysis study was developing a method for determining the best locations for injecting renewable energy resources to improve transmission system reliability. The second objective was calculating the economic and social benefits of in-state renewable potential locations to meet the 20 percent renewable energy target by 2017. This study was successfully completed in 2005.

Following this study, BEW Engineering participated in the Intermittency Analysis Project for the Energy Commission in 2007. This Intermittency Analysis Project study evaluated the potential transmission effects of intermittent (variable generating) renewable resources, as the renewable target is increased to 33 percent by 2020. The study evaluated the effects as a higher percentage of renewable energy is produced from California located wind and solar resources.

The Northern California Regional Integration of Renewables study expands on the two above-mentioned studies. The Regional Integration of Renewables study concentrates on Northern California only and analyzes the transmission needs to meet the 33 percent renewable energy target for Northern California utilities. It considers both in-state and out-of-state renewable energy potentials for meeting the energy targets. Since the exact renewable locations are unknown, the study evaluates various potential delivery points of renewable energy into the Northern California transmission grid. This evaluation technique is used to select the most probable transmission upgrades (characterized as “least regrets” transmission planning) needed to deliver power from source to sink.

These transmission upgrades are studied in detail to develop a priority list to advise the transmission owners and state agencies. Using the priority list, the transmission owners can begin developing the needed transmission expansion and timelines for construction/permitting. The objective is the delivery of renewable energy and other resources from any location within the Western Electricity Coordinating Council region once the power enters the Northern California grid to load centers in Northern California. As such, the study does not consider the transmission expansion needed in Southern California or in the out-of-state regions to deliver the power to the Northern California delivery points.

Goals and Objectives

The goals and objectives of the Northern California Regional Integration of Renewables study are:

- Focus on statewide transmission *planning options* to help meet policy objectives.
- Focus on providing *quantitative impacts* (pros and cons) of various options on transmission reliability, congestions and mix of renewable technologies.

- Develop *tools and analysis methods* to evaluate transmission for renewables along with conventional generation.
- Provide a *common perspective* for evaluating different technologies competing for limited system resources.
- Provide a *common forum* for Commissions, utilities, and developers to examine the location and timing of new generation/transmission projects and public benefits of these resources.
- Make planning of the transmission system easier to support customer loads,
 - In advance of availability of specific resource information.
 - Beyond the confinements of single transmission owners in Northern California for 2015 -2020 and later.

Conclusion

Based on analysis of the 10 renewable resource scenarios and the 12 conceptual transmission options, this study determined that a 500-kV connection between Bakersfield (Midway Substation) and Fresno (Gregg Substation) and a 500-kV connection between Shasta County (Round Mountain Substation) and Stockton/Contra Costa County (Tracy/Tesla Substations) would offer the most relief in potential transmission overloads to enable meeting a renewable resource penetration of 33 percent by 2020. These proposed facilities are categorized as part of the “least regrets” transmission upgrade. Several 500-kV transmission connections linking Tracy/Tesla Substations, Cottle Substation, and Gregg Substation are also found to be beneficial for facilitating renewables development. In addition, depending on the locations and amounts of the renewable resource located north of California, extension of the 500-kV connection northward may be needed.

Next Steps

The original scope of the Northern California Regional Integration of Renewables Project envisioned that, after a prioritized list of transmission expansion projects was developed, there would be subsequent simplified feasibility and cost estimate effort. In particular, that effort would have included an assessment of the technical feasibility and transmission cost estimates for the implementation of the transmission projects. However, since the 2007 inception of the Regional Integration of Renewables Project, other efforts have been initiated, including the Renewable Energy Transmission Initiative, the California Transmission Planning Group and, more recently, the California Independent System Operator’s Renewable Energy Transmission Planning Process proposal.³ The California Transmission Planning Group is developing a

³ The California Transmission Planning Group (CTPG) is a forum for conducting joint transmission planning and coordination in transmission activities to meet the needs of California consistent with FERC

statewide transmission plan to meet the state's 33 percent by 2020 Renewables Portfolio Standard goal, with a view toward actually implementing transmission system expansions. Therefore, rather than duplicating those other efforts, this final report represents the completion of the Regional Integration of Renewables Project. The information and method developed through the Regional Integration of Renewables Project will be turned over to the California Transmission Planning Group and other stakeholders to support their forward-looking analyses.

Note: All tables, figures, and photos in this report were produced by the authors, unless otherwise noted.

Order 890. Please see the CTPG website at <http://www.ctpg.us/public/index.php> for information on the objectives, activities, stakeholder comments, schedule, and reports.

CHAPTER 1:

Project Background

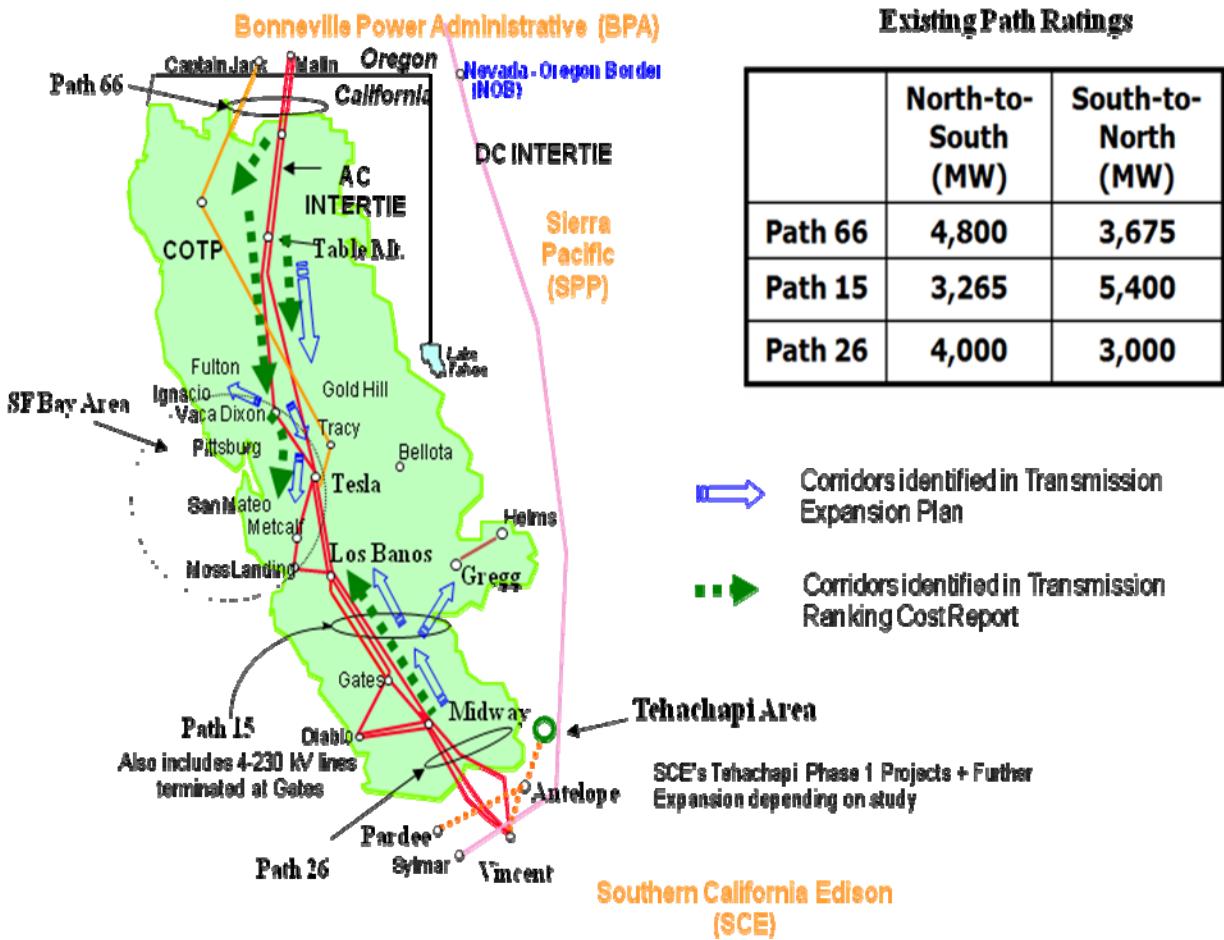
A number of out-of-state high voltage transmission lines being developed within the Western Electricity Coordinating Council (WECC) System could increase transfer capabilities to move renewable power into California. Projects currently under consideration are shown in WECC TSS Ratings and Progress Report Logs. There is a need to investigate transmission impacts associated with the expected operations of these new lines while meeting industry reliability standards including: Planning Standards and Criteria of the North American Electric Reliability Corporation (NERC) and the WECC; California Independent System Operator (California ISO) Planning Criteria and supporting Grid operations.

Depending on the renewable resource type, the Northern California electric utilities may require more than 6,000 megawatts (MW) of new renewables to meet the Northern California's share of the state mandated targets of 33% of energy consumed by 2020, if the energy is to be provided by 100 percent wind or solar technology. These new renewable resources are in addition to the existing, quantified renewables and renewables currently under contract as of 2008. To reach an RPS target of 33% and maintain reliability, adequate transmission options must be planned as soon as possible. Currently, it could require about 5 years to build a major new 230 kV line and about 10 years to build a major new 500 kV line. The high concentration of in-state and out-of-state renewable resources must be interconnected to the existing high voltage transmission grid at some existing or new substation located on the grid and delivered to the load centers. These factors, in combination with the long lead time for construction, means transmission alternatives must be planned today.

Error! Reference source not found. shows the existing major transmission power flow pathways for Northern California. As previously stated, major new renewable penetrations must connect to an existing or new substation on the transmission grid shown on**Error!**

Reference source not found. The power from these potential renewable resources will increase the power flow to the load centers over the existing high voltage lines, which are already heavily loaded today. Depending on the locations of the new resources entering the grid, the power may not be moved across the grid without major upgrades.

Figure 3: Major Transmission Pathways in Northern California

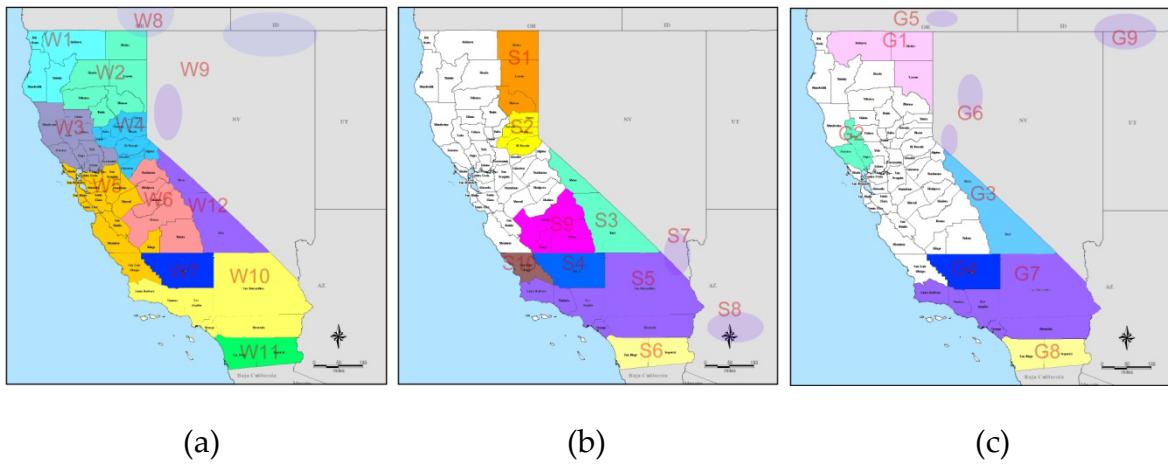


Source: RIR

The Northern California transmission grid is interconnected with the WECC grid through the California-Oregon Intertie (COI or Path 66) to the north, the 500 kV lines connecting Pacific Gas and Electric (PG&E) Company's Midway Substation (Path 26) to the Southern California Edison transmission system to the south, and the 115 kV and 60 kV lines connecting to Sierra Pacific Resources (Path 24) to the east. Power entering the Northern California transmission grid from out-of-state or from resources within California flows towards the load centers through these electrical paths and would affect the transmission system in between. For example, power entering Northern California system from areas north of California or from in-state areas north of Glenn County, impacts the transmission system south of Round Mountain. Likewise, power entering the Northern California system from areas south of Fresno County or through Midway from areas in Southern California and the Desert Southwest, impacts the system north of Midway Substation.

Complicating the planning of new California transmission lines are uncertainties in the projected timing, penetration levels, locations and technology characteristics of the new renewable resources. As noted, the Energy Commission has supported extensive studies on renewable resource potential and characterizations. Figure 4 illustrates the diversity of the renewable regions for potential solar, wind and geothermal resources development. These maps are developed using the Energy Commission's SVA and the IAP data, new project information from a variety of sources including the Renewable Energy Transmission Initiative (RETI)^[4] and the California Independent System Operator Interconnection Queue list of registered renewable projects. Because transmission projects are mostly driven by new resources, displacement of existing resource, and load growth, uncertainty in resource development presents major uncertainty. Overbuilding of transmission facilities can cost the customers tens of millions of dollars with the associated environmental impacts. Under-building transmission facilities can delay development of viable renewable resources or adversely impact reliability.

Figure 4: Potential Renewable Resource Areas:
(a) Wind, (b) Solar (thermal & PV), (c) Geothermal



Source: RIR

To minimize uncertainties and increase the opportunities to build the optimum and “least regrets” transmission to meet a 33 percent renewable energy target by 2020 (CA RPS), the assessment methodology for the RIR starts with transmission planners working under a collaborative effort. This effort leverages the transmission and reliability expertise of transmission owners and utilities and applies a systematic transmission reliability metric approach developed as part of the SVA and applied in the IAP and other Energy Commission integration studies.

RIR Team Organization

The RIR Core Analysis Team (CAT) responsible for conducting the analysis is composed of the Northern California regulatory agencies, and entities that are registered planning coordinators, transmission planners and transmission operators at NERC including:⁴

- California Energy Commission (Energy Commission)
- Pacific Gas and Electric (PG&E)
- Sacramento Municipal Utility District (SMUD)
- Transmission Agency of Northern California (TANC)
- Western Area Power Administration, Sierra Nevada Region (WAPA)
- California Public Utility Commission (CPUC)
- California Independent System Operator (California ISO)

Industry experts from BEW Engineering (BEW) and staff from Lawrence Livermore National Laboratory (LLNL) round out the CAT.

As part of the Energy Commission public process, interested stakeholders (renewable developers, other utilities, etc.) provide input and guidance to shape and refine the renewable resource identification process and the study scenario development through bimonthly RIR stakeholder conference calls.

⁴ See NERC Reliability Functional Model (<http://www.nerc.com/page.php?cid=2|247|108>)

CHAPTER 2:

Project Methodology and Approach

Traditionally, transmission planning is done to assess the reliability of the transmission system based on anticipated project-specific resources, loads, and transmission topology. If conceptualizing longer-term transmission expansion includes explicit consideration of renewable resource potentials (in advance of generator-specific information), then a new, more proactive approach to transmission planning is needed. A new approach is also needed, if financial risk to ratepayers and impacts on the environment are to be minimized. The proactive approach developed under the RIR brings together responsible transmission planning entities to:

- Coordinate the development of “least-regrets” transmission options with explicit consideration of renewable resources and policy targets
- Study common transmission impacts and complementary strategies for the region
- Develop a process to account for system-wide impacts and benefits and minimizes system reliability impacts and costs for ratepayer

The steps include:

1. Update the renewable resource database with the latest publicly available information (i.e., California ISO, Energy Commission, other transmission working groups) and apply the transmission reliability metric to develop the renewable resource mixes or renewable resource scenarios
2. Develop transmission planning base cases for summer peak, winter off-peak and spring peak utilizing cases developed by the Western Electricity Coordinating Council (WECC) and associated assumptions for reliability analysis (e.g. maximum intertie flows)
3. Conduct penetration and overload sensitivity studies to identify initial list of transmission considerations needed to supply projected load and reliably inject renewable resources
4. Develop transmission scenarios study options based on sensitivity studies
5. Analyze each option using industry transmission planning models to develop conceptual transmission upgrades, contingencies and other reliability considerations
6. Identify the transmission upgrades that are *common* to more than two renewable resource scenarios

7. Run sensitivity studies with projected load increased and decreased by X%
8. Consider impact of varying climate conditions if applicable (i.e. hydro variation, carbon footprint reductions)
9. Develop reconnaissance-level cost estimates for each transmission upgrade
10. Categorize the transmission upgrades/expansions based on factors including:
 - o Reconnaissance-level cost for implementing and value to the region
 - o Ability to reliably support a large number of renewable resource scenarios
 - o Ability to support other public benefits including the most economic, most, carbon neutral or others as applicable
11. Provide categorized transmission options and identified benefits
12. Document proactive transmission planning process, findings and lessons learned

The methodology is developed and refined with the cooperation with the CAT and utility industry. To meet regulatory requirements, the approach utilizes standard industry planning tools, WECC accepted transmission datasets (i.e. base cases), publicly vetted and available renewable resource information (MW, resource areas), regional contingencies, and assumptions based on local utility input for developing the transmission scenarios and GIS-based visualization.

Selection of the Reference Base Case

PG&E provided BEW with the latest 2017 WECC summer transmission power flow case with updates by PG&E for the Northern California transmission system. The 2017 case was vetted through the California ISO transmission planning process and is used by PG&E in its transmission planning and grid analysis studies. This 2017 case is considered the starting base case to develop the 2020 summer, spring, and fall power flow cases for the RIR study.

The Energy Commission Electricity Analysis Office (EAO) provided the load forecast projections for use to develop the 2020 case. Table 1 shows the Energy Commission load forecast in MW for each Energy Commission planning area and each major California utility.

Table 1: Energy Commission 2020 Projected Load Forecast

EAO Planning Area	Agency	2020 load MW	EAO Planning Area	Agency	2020 Load MW
PG&E	Alameda	72	SCE	Anaheim	634
	Biggs	6		Anza Electric Cooperative, Inc.	19
	Calaveras Public Power Agency	6		Azusa	71
	Central Valley Project (WAPA)	217		Banning	63
	Gridley	14		Bear Valley Electric Service	15
	Healdsburg	26		Boulder City/Parker Davis	24
	Lassen Municipal Utility District	31		Colton	122
	Lodi	184		Metropolitan Water Department	186
	Lompoc	31		Rancho Cucamonga	17
	Merced Irrigation District	95		Riverside	771
	Modesto Irrigation District	866		SCE Bundled	24,129
	Palo Alto	196		SCE Direct Access	1,615
	PG&E Bundled	22,522		Valley Electric Association, Inc.	1
	PG&E Direct Access	967		Vernon	192
	Plumas-Sierra Rural Electric Cooperation	31		Victorville Municipal	5
	Port of Stockton	4	SCE Total		27,864
	Power and Water Resource Purchasing Authority	49	LADWP	LADWP	6,004
	Redding	326	BUGL	Burbank	299
	Roseville	451		Glendale	311
	San Francisco	124	BUGL Total		610
	Shasta Dam Area Public Utility District	37	PASD	Pasadena	307
	Silicon Valley Power	544	SDG&E	SDG&E Bundled	4,802
	Tuolumne County Public Power Agency	5		SDG&E Direct Access	598
	Turlock Irrigation District	587	SDG&E Total		5,400
	Ukiah	40	IID	Imperial Irrigation District	1,467
PG&E Total		27,430			
SMUD	SMUD	3,733			
	Northern California Total Load	31,163		Southern California Total Load	41,652

Source: RIR and CEC-200-2007-015-SF2

The 2017 WECC power flow was developed in 2006 with the load forecast prepared by the individual utilities. Each utility uses its own internal assumptions to prepare the load forecast. When PG&E updated the 2017 power flow data for its own internal studies, PG&E updated the load forecast to match the latest forecast prepared by the utilities. Initially, the CAT decided to use the Energy Commission long-term load forecast for consistency to escalate loads to 2020. Table 2 compares the utility loads in the 2017 WECC power flow case to the Energy

Commission 2017 and 2020 forecasts (Columns 2, 3, and 4). Although the Northern California total load projections between the two 2017 forecasts are close, the individual utility forecasts are significantly different for some utilities.

Table 2: Comparison of California Utility Load Forecasts

Area	2017 WECC Case (MW)	Energy Commission 2017 Forecast MW	Energy Commission 2020 Forecast MW	RIR 2020 Forecast MW
PG&E & other utilities	21,580 ⁵	21,995	22,847	22,473
PG&E customer owned	1,047	966	967	1,050
Subtotal PG&E	22,517	22,961	23,814	23,523
WAPA-SNR	242	217	217	245
Redding	301	308	326	315
Modesto	952	826	866	996
Turlock	608 ⁵	559	587	651
Roseville	450	421	451	459
DWR	19	21	21	21
NCPA	513	583	604	556
Santa Clara	589	529	544	614
SMUD	3,902	3,602	3,733	4,078
Northern California	30,203	30,027	31,163	31,458
SCE, customers & Pasadena	23,978	27,047	28,171	28,157
LADWP-Bur-Glen	7,794	6,554	6,619	6,921
SCE area	31,772	33,601	34,790	35,078
SDGE	5,452	5,197	5,400	5,400
Imperial	1,577	1,360	1,467	1,467
Southern California	38,801	40,158	41,657	41,945

Source: RIR and CEC-200-2007-015-SF2

The inconsistency between the WECC 2017 and the Energy Commission 2020 load forecasts is similar to the comparison to the Energy Commission 2017 forecast. CAT final decision used a 1.5% escalation rate to adjust the 2017 WECC power flow case loads to 2020 (right-hand column). The final comparison of the utility load forecasts between the Energy Commission 2020 load forecast (31,163 MW) and the new RIR 2020 load forecast (31,458 MW) using the 1.5% escalation are shown in Table 2. There is a 295 MW load difference between the two 2020 load forecasts, but the 2020 RIR forecast is more consistent with the WECC 2017 case.

A separate comparison is completed for Southern California as shown in Table 2. When PG&E updated the Northern California power flow data set, PG&E did not change Southern

⁵ In the WECC 2017 Base Case, Merced Irrigation District load of 109.6 MW was modeled together with Turlock Irrigation District (TID) load. To provide direct comparison with the Energy Commission Load Forecast, this 109.6 MW was moved from "TID" to "PG&E and Other Utilities".

California load forecasts. There is a significant difference between the 2017 WECC power flow load forecast (38,801 MW) and the Energy Commission 2017 load forecast (40,158 MW). CAT decided to use the Energy Commission 2017 forecast to adjust the loads in Southern California to 2020.

The energy forecasts will be used in the determination of the renewable energy targets. That discussion is discussed in a later section.

Energy Commission Load Forecast, Energy Efficiency, and Photovoltaic Penetrations

In 2008, the Energy Commission prepared a load forecast projection through 2020 for all of the investor owned utilities (IOU) and the major public owned utilities (POU). The load forecast is the coincident summer peak demand by planning area and includes the impacts of PV incentive programs. The Planning Areas were P&GE, SCE, SDG&E, SMUD, LADWP, IID, BUGL, and PASO.

For 2020, the Energy Commission forecasted a total installed photovoltaic penetration of 1,109 MW that is a combination of residential and commercial. However, at time of system peak, the derate factor applied to the installed capacity varied by planning area. When applied, the derate value represents the amount of PV that is generating at the time of the summer peak in the respective planning area. For Northern California, the Energy Commission projected 660 MW of installed PV with only 322 MW generating at time of peak. Southern California had a projected PV of 449 MW. For the entire state, the installed PV is 1,109 MW with the PV generation projected at 519 MW at the time of peak. This projected PV generation was reflected in the load projection as load reduction.

The Energy Commission projected 15% of the installed PV is residential, and the remaining PV is commercial. That corresponds to an amount of residential PV generation on the Northern California system of 48 MW ($322 * 15\% = 48$ MW) and for the entire state of 78 MW ($519 MW * 15\% = 78$ MW).

The Northern California RIR study was originally to include an analysis of the transmission benefits and impacts of 3,000 MW of installed residential PV across the entire state, of which 1,079 MW is located in Northern California. This residential penetration is defined in the California Solar Initiative for one million new homes to have PV. However, the Energy Commission forecasted installed residential PV penetration for 2020 was less than 6% of the 3,000 MW anticipated. The CAT then considered increasing the Energy Commission load forecast to account for the residential PV peak load reduction of 48 MW for Northern California. However, since the residential PV values are so small compared to the peak loads, no corrections are made. Table 3 shows the PV values used in the 2020 Energy Commission summer load forecast.⁶

Table 3: PV Forecast Into the Energy Commission Forecast (MW)

Planning Area	Cumulative Installed Forecast 2020	Derate factor applied to installed capacity:	Total Available PV at Peak for 2020	Residential PV	Commercial PV
PGE	640	0.5881	316	47	269
SCE	301	0.5479	140	21	119
SDGE	114	0.5145	46	7	39
SMUD	20	0.5777	6	1	5
LADWP	29	0.5430	9	1	8
IID	2	0.5531	1	0	1
BUGL	1	0.5394	1	0	0
PASD	1	0.5394	0	0	0
Total	1,109		519	78	441

Source: CEC-200-2007-015-SF2

In the 2020 summer power flow data sets, two base cases are developed and studied. The first data set models the 3,000 MW of PV as if it was generating at the time of system peak. The second models the derated PV capacity of approximately 1,620 MW. The objective of the two cases is to determine the transmission benefits of higher penetrations of PV. The source of this data is *California Energy Demand 2008 - 2018: Staff Revised Forecast, FINAL Staff Forecast, 2nd Edition*, publication #CEC-200-2007-015-SF2. (Acrobat PDF file, 259 pgs, 3.4 MB). Posted: 11/16/07, updated 11/27/07., forecast detail corrected 3/29/2008.

⁶ Even if commercial PV penetration were included, the total installed PV would be about 1/3 of the 3,000 MW anticipated, with the PV generation at the time of system peak to be about 322 MW for Northern California. This is about 1.2% of the Northern California peak load, the impact of spreading this load increase over the Northern California is not considered significant in terms of developing a conceptual transmission plan.

CHAPTER 3:

Base Case Development

Development of 2020 Summer Base Case

The summer power flow case development begins with the PG&E 2017 WECC approved and solved data set. Corrections are made for the 2020 peak load and additional residential PV as previously discussed. In analyzing the power flow model, there are line and substation overloads, bus voltage violations, and interface (Path rating) violations. In the initial base case development, it is important to define the resource types that are dispatchable to serve load. The dispatchable resources are generating resources from natural gas, diesel, and coal. These dispatchable resources are reduced starting with the highest cost generators as new conventional and renewable resources are added in the scenario cases.

The non-dispatchable resources have generation patterns that are either costly or difficult to change to integrate other generation or accommodate variations in load. For example, hydro generation has largely fixed generation patterns and capacities, and existing renewable resources are non-dispatchable in the power flow cases for the different simulated seasons. Base load geothermal and biomass resources are non-dispatchable and are operated at maximum capacity, when available. As new resources are added to the system, the new and existing renewable resources continue to be assumed non-dispatchable. Other resources such as the nuclear and qualifying facility resources are non-dispatchable.

The interface (Path) flows are fixed at maximum imports and exports for all seasons and power flow directions. The objective is to preserve existing import capabilities as more renewables are installed to meet renewable energy targets. NERC Standard TOP-004, Requirement 4 does not allow operation “in any state for which valid operating limits have not been determined” for more than 30 minutes.⁷ Therefore, any reduction in import capabilities assumed will likely lead to a reduction in operating import capability in the future.

Since there is a limit to the amount of re-dispatch that can be made to these “conventional” resources, the redispatch may result in new overloaded elements, low voltage and stability problems in the power flow data set. There may be a finite limit to the total renewable capacity that can be installed on the system as a result of the limitations in redispatching generation. This limitation should be further investigated.

⁷ NERC Standard TOP-004-2 (<http://www.nerc.com/files/TOP-004-2.pdf>), Requirement 4 states, “if a Transmission Operator enters an unknown operating state (i.e. any state for which valid operating limits have not been determined), it will be considered to be in an emergency and shall restore operations to respect proven reliable power system limits within 30 minutes.”

Development of the 2020 Spring Peak and Fall Off-Peak Base Cases

The RIR 2020 Spring Peak and Fall Off-Peak cases are developed from the RIR 2020 Summer Peak case and the spring and fall cases from the Intermittency Analysis Project. Table 4 shows the spring peak, summer peak and fall off-peak loads in MW for Northern and Southern California.

Table 4: Spring, Summer and Fall Loads (MW) for California

Utility	Spring On-Peak	Fall Off-Peak	Summer On-Peak
N. California	24,605	13,858	31,459
S. California	30,814	17,735	41,945
Total	55,419	31,593	73,404

Source: RIR

Determination of Regional Renewable Energy Targets

Although the 2020 renewable energy target is 33 percent, adjustments are required to account for existing renewables, and CPUC approved contracted renewables and those that have signed interconnection agreements. In the previous sections, the 2020 load forecast development is discussed. The load forecast includes both the customer energy consumption and system losses to transmit the power from source to load. The renewable energy target is based on customer energy consumption. The CAT used an average loss factor of 6% to represent system losses over the entire state consistent with the IAP study. The 2020 energy forecast is reduced by 6% so that the renewable energy target only is applied to the projected customer energy consumption as shown in Table 5.

Table 5: Calculation of Renewable Targets for 2020 (GWh)

	N. California Public Power		PG&E	Total N. CA	SCE,LADWP,SDGE, IID, others	System Total
	N. California Public Power except SMUD	SMUD				
2020 Load Forecast minus 6% Losses (GWh)	15,280	12,350	94,463	122,093	166,538	288,631
Total 33% Target (GWh)	5,042	4,076	31,173	40,291	54,958	95,248
2004 Existing Renewables (GWh)	1,587	1,091	9,928	12,606	13,417	26,023
Renewables under contract (GWh)	-			8,621	-	8,621
Net Additional 33% Target (GWh)	3,455	2,985	21,245	19,064	41,541	60,604

Source: RIR

The projected Northern California renewable energy target, under a total 33% renewable target, is 40,291 GWh. There are 12,606 GWh of existing qualified renewables and 8,621 GWh of CPUC/Energy Commission-approved contracted renewables as of 2008. The overall net renewable energy need in 2020 to meet the 33% target is 19,064 GWh.

The additional renewable capacity required to meet the projected renewable energy target depends on the renewable mix. If the energy is served entirely from geothermal resources, Northern California requires about 2,400 MW of additional geothermal capacity. As a comparison, if the energy is served entirely by wind resources, Northern California requires about 5,900 MW of additional wind capacity. Neither of these extreme conditions occurs, so the installed renewable capacity varies between the two extremes. This study concentrates on the transmission requirements under various combination and locations of the additional renewable resources.

For Southern California, the utilities energy is aggregated. For the same 33% target, the renewable energy requirement is 54,958 GWh. After subtracting the existing renewable energy of 13,417 GWh, the net requirement to meet 33% renewable energy by 2020 is 41,541 GWh. Although the Southern California utilities contracted for a portion of their renewable energy needs, the utilities did not provide specific locations and contractual limits for these resources. There is a list of CPUC approved Southern California Edison (SCE) renewable contracts but the locations are only provided by county. The renewables for Southern California entities are represented using the CPUC-approved list and the California ISO queue list for renewable projects. The potential IAP renewable locations are used to select renewable locations and installed capacity for potential generation projects with undisclosed or unknown locations. For simplicity, potential renewable energy purchased from generating plants located in Mexico and

the Desert Southwest is represented at locations within Southern California. Because this is a study on the transmission needs in the Northern California transmission system, this simplified representation will not impact the study results.

Southern California Power Flow Data Set Modifications

In the 2017 WECC data set, some of the major Southern California transmission projects are not included, such as the Tehachapi upgrades, Palo Verde-Devers II, SDG&E new transmission project, and upgrades in the Imperial Valley area. Southern California Edison upgraded the 2017 WECC data set for known transmission projects.

Since the RIR study concentrates on transmission requirements to meet the renewable energy targets in Northern California only, the Southern California renewable mix is predetermined to represent RPS of 33% for Southern California load only and modeled in the base case. As impacts of renewables to supply load in Northern California are studied, the exact locations of Southern California renewables do not impact RIR decisions regarding transmission in Northern California.

The Southern California renewable resources to supply Southern California loads are modeled at in-state locations. Two sources are used to determine the renewable mix and locations. The primary source is the IAP study. In the IAP study, a 33% renewable penetration mix is developed for 2020 for the entire state. The second source is the CPUC-approved list of renewable contracts. Once the renewable resource mix for Southern California is selected using the IAP data, the locations and renewable capacities are compared to the CPUC renewable list. Since the CPUC list did not specify the exact location of the renewables, the comparison verifies that the approximate locations selected from the IAP list are consistent with the contracted locations.

In the IAP study, there is a very high penetration of wind generation since the objective of the study is the impacts of intermittent resources on the transmission grid. Wind provided the highest variability of generation for the IAP study. For the RIR study, the penetrations follow the current renewable development trends. The penetration of solar resources is increased to correspond to increased contracted amounts from the utility's RPS process and submittals to the California ISO interconnection queue list. The Imperial Valley geothermal penetration is reduced since there are fewer projects listed in the Imperial Irrigation District and California ISO interconnection queue lists. In reviewing the Southern California renewable lists in Table 6, there should not be any significance assigned to the renewable mix or the renewable locations. The renewable resources in the list were selected solely to meet the RPS requirements for the RIR study and not to explicitly prioritize locational benefits of the future resources.

Since the renewable targets are energy targets, a projected annual capacity factor for the renewable resources determines the renewable capacity mix. The capacity mix is modeled in the power flow while the energy is modeled in a production costing simulation model. It should be recognized that the actual capacity factor may be different from year to year for the intermittent resources since the environmental influences from wind speeds and cloud formations drives the generation. Table 6 shows the results of the Southern California renewable energy penetration targets.

There is a difference in the renewable energy target between the IAP and the RIR study. In the IAP study, the renewable energy target is based on the total energy consumption that included the 6% system losses. In the RIR study, the system losses were removed, and the energy target is based on customer usage. The second reason for the energy difference is the installation of more wind resources in Southern California in the IAP Study to increase the amount of variable generation.

Table 6: Comparison of Southern California IAP Locations to the RIR Locations

Location	Technology	Capacity Factor %	IAP Study		RIR 33%	
			MW	Energy (GWh)	MW	Energy (GWh)
Salton Sea	Geothermal	90.0%	1,400	11,038	750	5,913
Brawley North	Geothermal	90.0%	135	1,064	120	946
Brawley East	Geothermal	90.0%	129	1,017	129	1,017
Urban, Agr, Veg	Biomass	90.0%	494	3,895	494	3,895
Tehachapi	High Wind	37.0%	4,500	14,585	3,500	11,344
Riverside	High Wind	37.0%	1,416	4,590	700	2,269
San Bern	High Wind	37.0%	640	2,074	500	1,621
SDGE	High Wind	37.0%	500	1,621	500	1,621
LADWP Wind	High Wind	37.0%	200	648	200	648
Imperial	High wind	37.0%	600	1,945	600	1,945
Ventura	Low Wind	25.0%	50	110	50	110
San Diego	CSP	27.0%	100	237	100	237
Imperial	CSP	27.0%	400	946	600	1,419
Riverside	CSP	27.0%	200	473	700	1,656
San Bern	CSP	27.0%	300	710	1,000	2,365
Kern	CSP	27.0%	-	-	600	1,419
SCE CSP	CSP	27.0%	850	2,010	850	2,010
SDG&E CSP	CSP	27.0%	500	1,183	500	1,183
Southern CA Total			12,414	48,146	11,893	41,618

Source: RIR

New California Conventional Gas Generation Additions

Table 7 lists the new conventional gas generation added to the 2020 case. These locations and megawatt sizes are from the Energy Commission IAP study. The Energy Commission Electricity Analysis Office (EAO) previously completed production costing studies for 2017 and added new generation to serve load, meet reserve requirements, and resource adequacy. These sites are used in the IAP and continue to be used for the RIR study. More information is provided in the IAP study. There is projected to be 5,849 MW of new gas generation by 2020. Of these, 2,101 MW are installed in Northern California based on the EAO study.

Table 7: Proposed Location and Capacity of new Gas Generation

AREA	BUS	NAME	MW
IID	21026	EI CENTRO	50
LADWP	26025	HAYNES	150
LADWP	26025	HAYNES	150
PG&E	30873	Helm	250
PG&E	30873	Helm	30
PG&E	30875	Mccall	250
PG&E	30624	Tesla E	150
PG&E	30873	Helm	250
PG&E	30875	Mccall	15
PG&E	31000	Humboldt	150
PG&E	33204	Potrero	150
PG&E	30560	Eastshore	265
PG&E	32786	OAK C115	150
PG&E	37585	Tracy	26
PG&E	37585	Tracy	265
PG&E	33540	Tesla	150
SCE	24151	VALLEY	387
TOTAL			
5,849			

AREA	BUS	NAME	MW
SCE	24151	VALLEY	387
SCE	24151	VALLEY	26
SCE	24077	LBEACH	150
SCE	24077	LBEACH	150
SCE	24077	LBEACH	150
SCE	24401	ANTELOPE	259
SCE	24401	ANTELOPE	259
SDG&E	22768	South Bay	140
SDG&E	22772	South Bay	360
SMUD	37524	Sutter	150
SMUD	37547	Folsom	150
SMUD	37549	Folsom	150
SMUD	37549	Folsom	150
SMUD	37016	Rancho Seco	250
SMUD	37016	Rancho Seco	250
SMUD	37016	Rancho Seco	30
TOTAL			
5,849			

Source: CEC-500-2007-081

Base Case Resource Adequacy and Reserve Margins

Major issues in higher penetrations of renewable resources are the impacts on planning reserve margins and resource adequacy. Table 7 lists the new gas generation that is available at the time of the system peak to serve load. For Northern California, there is 2,101 MW of new gas generation added to the system.

Table 8 lists the Northern California contracted renewables by renewable type as of October 2008. The renewables are divided into PG&E and Other Utilities (public power utilities). Each renewable type has its own percentage of capacity that can contribute to serving load and reserve margins (Resource Adequacy or RA) at the time of system peak. For example, biomass and geothermal are considered base-loaded, so 90% of the capacity contributes to RA. Although hydro generation is an energy-limited resource, hydro is dispatched as a peak-

shaving hydro resource, so that 100% of its capacity is available at time of system peak. According to Energy Commission forecasts, only 58% of the solar is coincident with the system peak. Wind is projected to have about 10% of the installed capacity available at the time of system peak. From the 1,879 MW of new contracted renewables, only 1,074 MW are projected to contribute to RA.

Table 8: Northern California Contracted Renewables Reserve Margin Calculation

PG&E	New MW	Capacity Factor	GWh	% for RA	MW for RA
Wind	475	37%	1,539	10%	47
Biomass	101	100%	887	100%	101
Hydro	3	40%	11	100%	3
Solar	738	25%	1,615	58%	428
Geo	315	100%	2,755	100%	315
Subtotal	1,631		6,807		894
Other Utilities	New MW	Capacity Factor	GWh		
Biomass	82	100%	723	100%	82
Geo	50	100%	439	100%	50
Wind	75	37%	657	10%	8
Hyd	40	40%	351	100%	40
Subtotal	247		2,170		180
Total	1,879		8,977		1,074

Source: RIR

The renewable capacity and energy from Table 8 is used to calculate the projected reserve margin shown in Table 9. From the power flow model, the maximum generation for each Northern California resource is multiplied by a projected percentage of peak availability factor to project a capacity value for resource adequacy calculations. In 2020, Northern California is projected to have a reserve margin of 13%, which is below the 15% requirement. The reserve margin increases to 23% after the new gas generation and contracted renewables are added to the system. This preliminary analysis will form the base, to which various projected renewable resource mix scenarios will be added, to reach the 33% RPS target.

Table 9: Northern California Reserve Margin Calculation

	Max MW	% Avail at Peak	Existing Peak MW for RM	Peak MW w/ contract renewables	Peak MW w/ new gas & contract renewable
Biomass	1,091	100%	1,091	1,091	1,091
Coal	205	100%	205	205	205
Dist Oil	134	100%	134	134	134
Existing Gas	20,330	100%	20,330	20,330	20,330
Geo	1,838	100%	1,838	1,838	1,838
Hyd	9,084	100%	9,084	9,084	9,084
Nuc	1,206	100%	1,206	1,206	1,206
Oil	150	100%	150	150	150
Other	71	58%	41	41	41
Solar	160	58%	93	93	93
Unknown	153	58%	89	89	89
Wind	798	10%	80	80	80
New Gas	2,101	100%	0	0	2,101
Contract Renewables	1,879	Varies	0	1,074	1,074
Total	39,199		34,340	35,414	37,515
N. CA Load	30,445		30,445	30,445	30,445
Reserve Margin			13%	16%	23%

Source: RIR

CHAPTER 4:

Pseudo-Generator Injection Analysis

The objective of “least regrets” transmission planning is the identification of transmission overloads that occur on the transmission grid under a wide range of different penetrations of new resources at different locations on the grid. Under each penetration scenario, the power flow simulation produces a list of transmission overloads. A matrix of transmission overloads can be defined that contains the most common and high risk transmission lines to be considered for upgrade or new lines constructed to minimize the risk of major line overloads. Since the objective is to select the most common and consistent transmission overloads occurring over a number of possible penetration scenarios, these lines become the “least regrets” lines.

In the previous sections of this report, the major transmission corridor for California runs from Oregon to Arizona. The Northern California transmission system is connected to the Pacific Northwest through the California-Oregon Interconnection (COI or Path 66) through Malin and Captain Jack Stations, to Southern California beyond through Midway station (Path 15 to the north of Midway and Path 26 to the south of Midway) and to Sierra Pacific Energy through the Summit Metering Station (Path 25). At the COI, there are three 500 kV transmission lines. Two lines constitute the Pacific AC Intertie (PACI) and are controlled by the California ISO, and the third is owned by the Transmission Agency of Northern California (TANC). The operations of these lines are governed by operating agreements.

These interconnection points are also defined Transmission Paths in the Western Electricity Coordinating Council (WECC) transmission grid. To identify the potential transmission problems, the base cases simulate power flow at or close to the maximum Path Ratings to provide appropriate stressed conditions. This is needed to preserve the respective future operating transfer capabilities because NERC/WECC standards do not allow operating under conditions that have not been studied.

Table 10: WECC Path and Path Ratings

WECC Path	Path Rating (MW)
Path 66 (COI) North to South South to North	4800
	3765
Path 15 (north of Midway) North to South South to North	3250
	5400
Path 26 (south of Midway) North to South South to North	3000 w/o RAS; 4000 w RAS
	3000
Path 25 (East tie) East to West West to East	150
	160

Source: RIR

The prevalent power flow through the Northern California system is from north to south during summer peak and spring conditions as the California utilities purchase excess Pacific Northwest hydro generation and renewable energy. During the fall and winter off-peak periods, prevalent power flow is from south to north as hydro generation is at minimum generation, and California utilities return the energy to the Pacific Northwest.

To assess the impacts of the added renewable resources, it would be instructional to investigate the impacts due to the injection points of the resources. Four major stations from various locations along the major transmission corridor for Northern California were selected. These are Round Mountain, Table Mountain, Tesla/Tracy, and Midway. Various levels of power were injected at the 500 kV buses of these substations. Because power injected at lower voltages will eventually flow, through displacement, into the major stations, the impacts of power at these injection points will provide insight into the impacts of resources connecting to the areas in the vicinity of these major stations, as well as imports from areas outside Northern California in the case of Round Mountain and Midway stations.

Generator injection analysis installs a pseudo-generator at one of the selected substations. A series of generator capacities are simulated in a power flow model under summer peak conditions. The 500 kV and 230 kV transmission overloads are recorded and saved for analysis. The pseudo-generator capacities range from 1,000 MW to 5,000 MW in 1,000 MW increments. These are single pseudo-generator injections.

For example, a pseudo-generator is installed on a Table Mountain 500 kV bus. The generator capacity is set at 1,000 MW and incremented up in 1,000 MW steps until 5,000 MW is reached. At each generator increment, a power flow simulation is completed. After all five simulations

are completed, the pseudo-generator is moved to a Round Mountain 500 kV bus and the procedure repeated. This continues until all substation simulations are completed.

Since it is unlikely that renewable energy is located at one substation and flows in one direction, a second set of pseudo-generator injections are simulated and studied. A pseudo-generator is installed at the Midway substation to represent power flows from resources around and south of Midway substation, and other pseudo-generators are installed at the other substations. This injection analysis studies the transmission impacts when power is delivered from both ends of the major transmission grid.

For example, a 1,000 MW pseudo-generator is installed at Midway, and another 1,000 MW generator is installed at Table Mountain and a power flow simulation completed. Both generators are incremented in 500 MW increments until both generators are at 2,000 MW. The Table Mountain pseudo-generator is moved to Round Mountain and the procedure repeated with the Midway generator.

In order to simplify tables, Line numbers (Line #) are used instead of the listing the full substation names. Table 11 below is a key to identify the major substation associated with the unique line number for the pseudo injection analysis.

Table 11: Line Numbering Key for Pseudo Injection Analysis

Line #	From Substation	To Substation	Nominal Voltage
Line 1	TABLE MT.	VACA DIXON	500
Line 2	ROUND MT.	TABLE MT.	500
Line 3	TABLE MT.	TESLA	500
Line 6	MALIN	ROUND MT.	500
Line 7	COTTONWOOD	ROUND MT.	230
Line 10	CPVSTA	CORTINA	230
Line 20	STAGG-J2	TESLA E	230
Line 23	EIGHT MI	TESLA E	230
Line 24	WESTLEY	LOS BANOS	230
Line 28	STOREY 1	WILSON	230
Line 29	STOREY 1	GREGG	230
Line 30	GREGG	FGRDN T2	230
Line 33	HERNDON	FGRDN T1	230
Line 45	COTWDWAP	ROUND MT	230
Line 46	COTWDWAP	ROSEVILL	230
Line 48	FOLSOM	ORANGEVL	230
Line 54	ROSEVILL	FOLSOM	230

Source: RIR

Single Pseudo Generator Injection Analysis

The outcome of these numerous power flow simulations is a list of potential transmission line overloads that occur on the 500 kV and 230 kV transmission lines. All of these overloads can be combined into tables: one for 500 kV line overloads and the second for the 230 kV line overloads. A priority list of transmission line overloads with the most number of overloads or the highest percentage of overload is then given to the Core Analysis Team (CAT) to determine potential solutions.

Single Generator Injection on 500 kV Lines

Table 12 shows the results of the single pseudo-generator injection analysis under summer peak conditions. The base case is first simulated to determine the existing potential transmission line overloads. Although there are more than four 500 kV transmission lines located in Northern California, the table shows lines 1, 2, 3, and 6, and their maximum percentage overload that occurred under first contingency analysis (N-1).

**Table 12: Single Generator Injection Analysis of the 500 kV Network
Under Summer Peak Conditions**

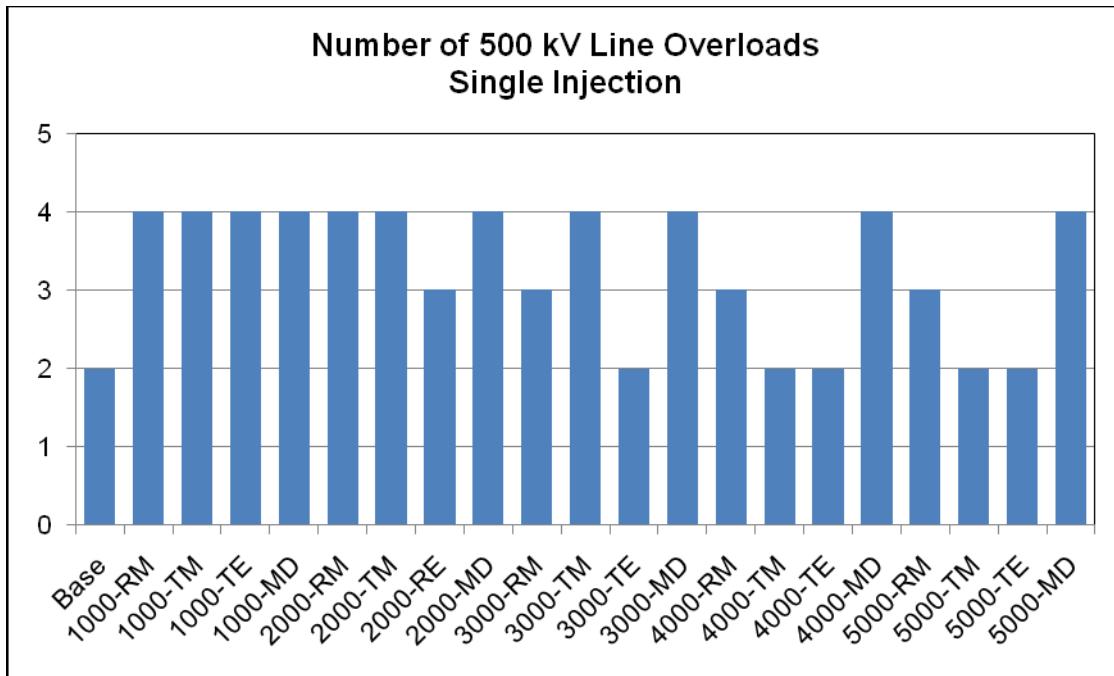
		Max % loading of Summer Emergency Rating			
500 kV Lines		Line 1	Line 2	Line 3	Line 6
	Range of loadings	101-252	102-294	100-233	102-127
		%	%	%	%
Base N-1 Contingency	Base Case	<100	110	<100	118
1000 MW Injection at:	Round Mountain	128	155	130	110
	Table Mountain	132	120	133	113
	Tesla	104	128	102	118
	Midway	106	130	104	120
2000 MW Injection at:	Round Mountain	151	184	157	107
	Table Mountain	158	110	164	112
	Tesla	101	126	<100	118
	Midway	105	130	103	121
3000 MW Injection at:	Round Mountain	173	221	182	<100
	Table Mountain	187	102	197	102
	Tesla	<100	124	<100	117
	Midway	136	131	103	123
4000 MW Injection at:	Round Mountain	197	252	216	<100
	Table Mountain	217	<100	233	<100
	Tesla	<100	122	<100	117
	Midway	105	131	102	125
5000 MW Injection at:	Round Mountain	230	294	169	<100
	Table Mountain	252	<100	186	<100
	Tesla	<100	121	<100	116
	Midway	105	131	100	127

Source: RIR

As pseudo-generators are installed at each of the major 500 kV substations and the capacity of the generator changes from 1,000 MW to 5,000 MW, the power flow simulation is completed and the overloaded 500 kV lines recorded. Lines 1, 2, and 6 are consistently overloaded in the majority of the simulations, including the base case. The percentage of loading varies with the generator injected capacity and ranges from the low 100% to over 290% of the Limit B rating.

Figure 5, shows the number of 500 kV lines that are overloaded under the different generator injections. Four 500 kV lines are overloaded under 11 of 21 power flow simulations. Two 500 kV line becomes overloaded in six of the simulations and three 500 kV lines become overloaded in four of the simulations. **Error! Reference source not found.** shows the number of lines impacted but does not indicate the commonality of the lines.

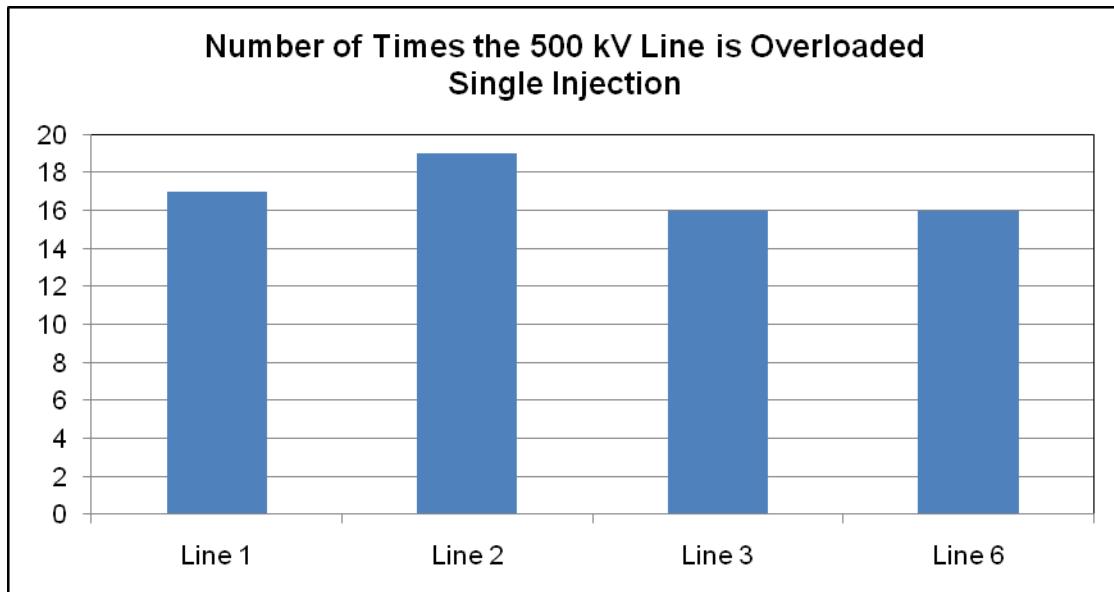
Figure 5: Number of 500 kV Line Overloads Under Summer Peak Conditions



Source: RIR

Figure 6 shows the number of times that a 500 kV line is overloaded under the 21 different power flow simulations. Line 1 is overloaded in 17 of the 21 scenarios. Line 2 is overloaded in 19 of the 21 scenarios, and Line 3 and Line 6 are overloaded in 16 scenarios.

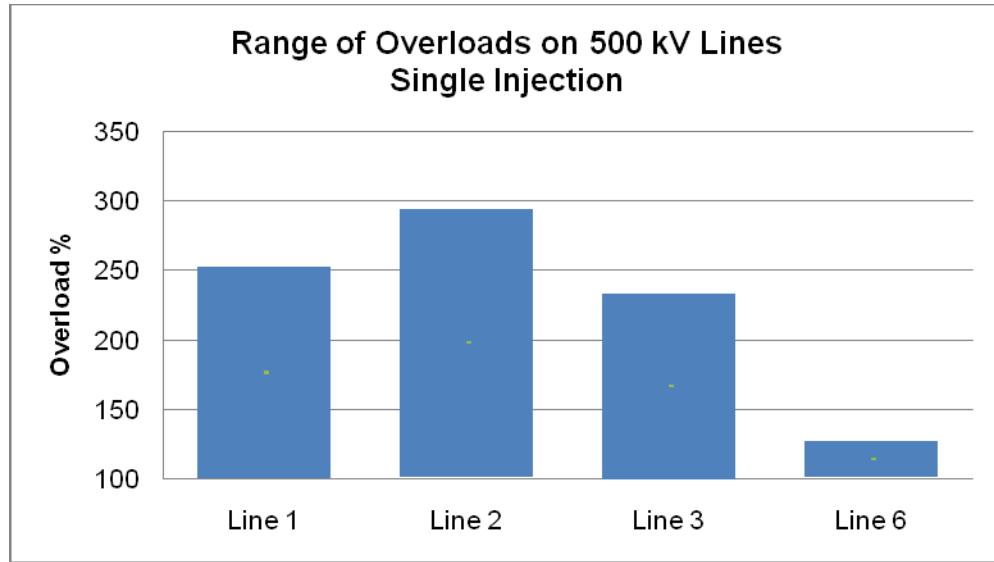
Figure 6: Number of Times the 500 kV Line Is Overloaded Under Summer Peak Conditions



Source: RIR

Figure 7 shows the range of overload for each of the 500 kV lines. For the 21 different scenarios, the percentage of overload under Limit B rating varies considerably. The range of loadings on Line 1 and Line 2 is from 103% to over 250% of the Summer Emergency ratings, depending on the pseudo-generator injection point and generator capacity. These two 500 kV lines are definite candidates for future analysis to determine the most likely overload that could occur on the lines.

Figure 7: Range of Overloads on 500 kV Lines Under Summer Peak Conditions

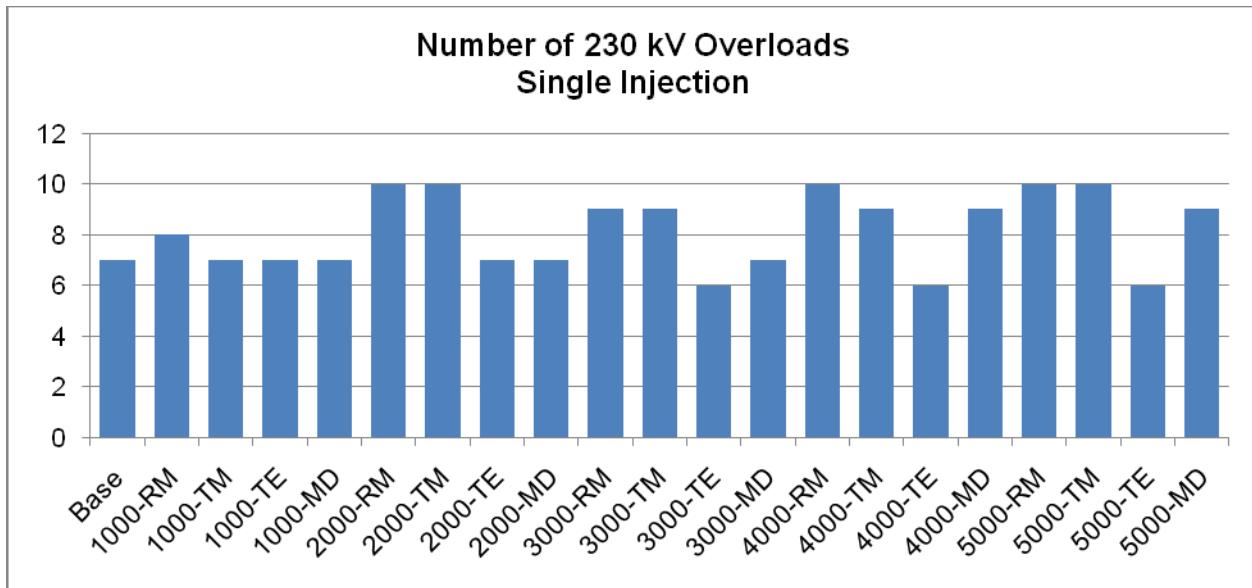


Source: RIR

Single Injection Analysis for 230 kV Lines

Table 13 shows the 230 kV line overloads for the single pseudo-generator injection analysis under summer peak conditions. There are thirteen 230 kV transmission lines that are projected to be overloaded in the base case and the generator injection cases. As shown in Table 13 and Figure 8, there are 21 power flow simulations completed for the single injection analysis. The maximum occurrences of 230 kV line overloads in any one simulation are 10, and the lowest occurrences of 230 kV line overloads are 6 lines.

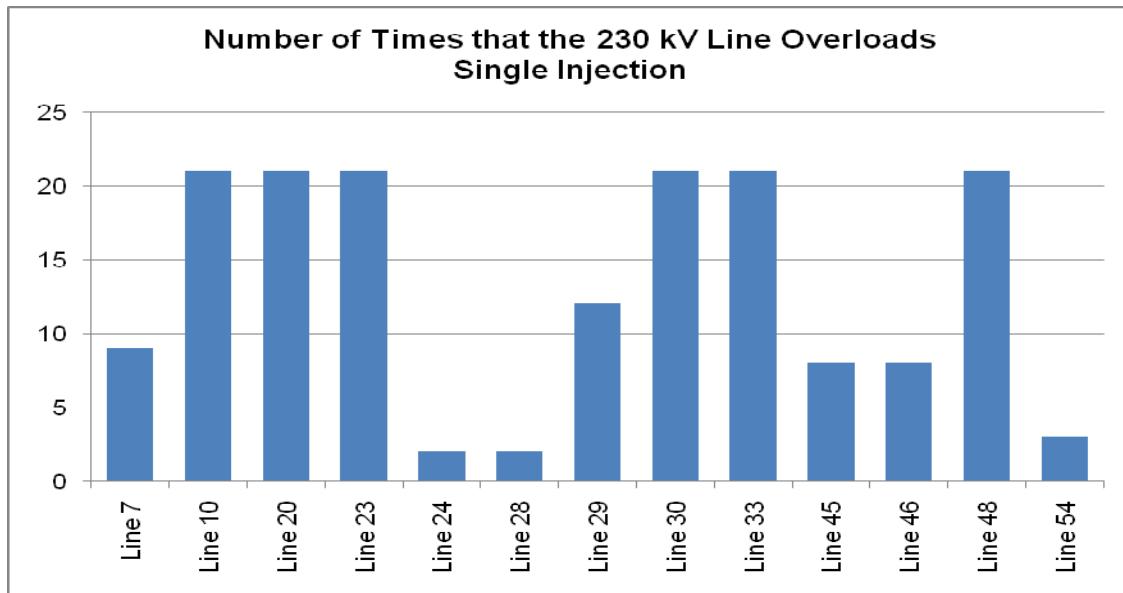
Figure 8: Number of 230 kV Overloads



Source: RIR

There is more variability in the number of times that a line is overloaded under the 21 different simulations as shown in Table 13 and Figure 9. There are six 230 kV lines that are overloaded under all simulations. The number of times that the remaining seven 230 kV lines are overloaded range from 2 to 12. At least six 230 kV lines require upgrades while the remaining lines depend on the locations that the new renewable generators are actually installed.

Figure 9: Number of Times That the 230 kV Line Overloads



Source: RIR

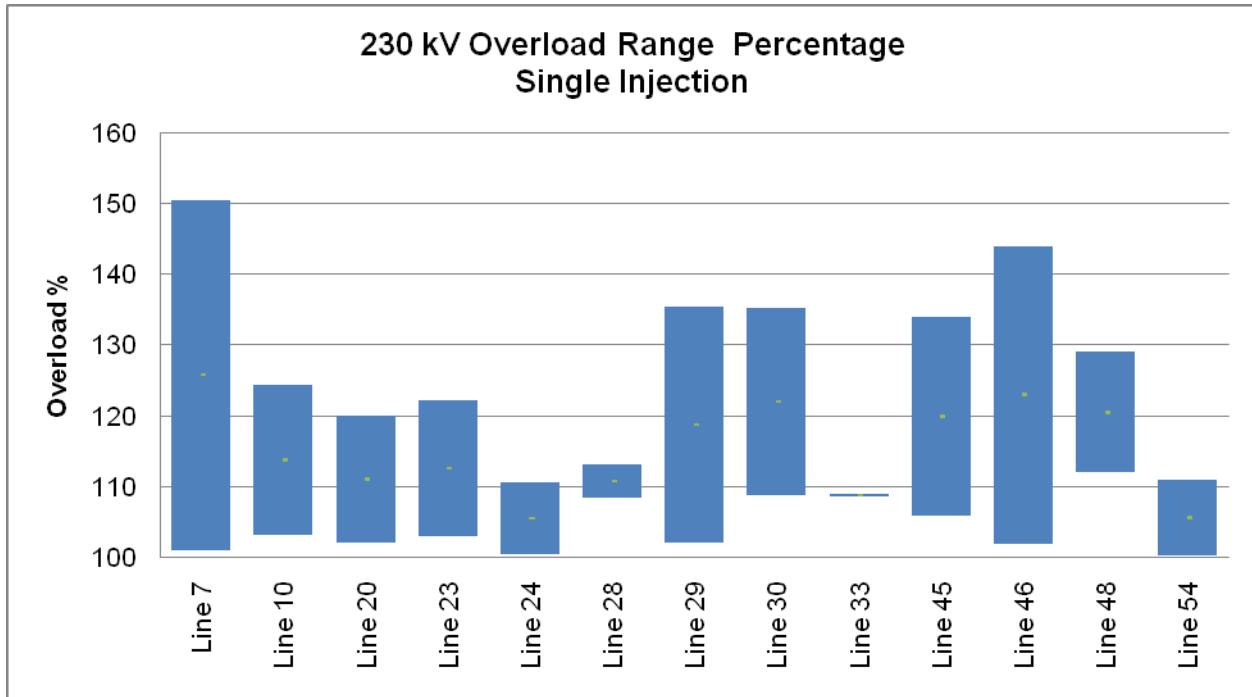
Table 13: Single Generator Injection Analysis of the 230 kV Network Under Summer Peak Conditions

		Overload indicated as % of Summer Emergency Rating												
230 kV Lines		Line 7	Line 10	Line 20	Line 23	Line 24	Line 28	Line 29	Line 30	Line 33	Line 45	Line 46	Line 48	Line 54
	Range of Overloads	101-151	103-124	102-120	103-122	101-111	109-113	102-135	109-135	109-109	106-134	102-144	112-129	100-111
Base @N-1	Major Substation		X	X	X			X	X	X			X	
1000 MW Injection	Round Mountain	X	X	X	X			X	X	X			X	
	Table Mountain		X	X	X			X	X	X			X	
	Tesla		X	X	X			X	X	X			X	
	Midway		X	X	X			X	X	X			X	
2000 MW Injection	Round Mountain	X	X	X	X			X	X	X	X	X	X	
	Table Mountain	X	X	X	X			X	X	X		X	X	
	Tesla		X	X	X			X	X	X			X	
	Midway		X	X	X			X	X	X			X	
3000 MW Injection	Round Mountain	X	X	X	X				X	X	X	X	X	
	Table Mountain	X	X	X	X				X	X	X	X	X	
	Tesla		X	X	X				X	X			X	
	Midway		X	X	X			X	X	X			X	
4000 MW Injection	Round Mountain	X	X	X	X				X	X	X	X	X	X
	Table Mountain	X	X	X	X				X	X	X	X	X	
	Tesla		X	X	X				X	X			X	
	Midway		X	X	X	X	X	X	X	X			X	
5000 MW Injection	Round Mountain	X	X	X	X				X	X	X	X	X	X
	Table Mountain	X	X	X	X				X	X	X	X	X	X
	Tesla		X	X	X				X	X			X	
	Midway		X	X	X	X	X	X	X	X			X	X

Source: RIR

In the previous two figures, the number of 230 kV overloaded lines and the number of times that a 230 kv line are overloaded are shown. Figure 10 adds another level of analysis by analyzing the range of percentage overloads over the 21 scenarios. Line 7 is overloaded in 9 of the 21 scenarios, and the range of loading varies from 100% to 140%. Furthermore, the overloads only occurred when more than 2,000 MW is injected at either Table Mountain or Round Mountain. The final determination as to the course of action to resolve the overload depends on the probably of installing 2,000 MW of new resources at either of these substations without additonal transmission upgrades.

Figure 10: Range of Overloads on Each of the 230 kV Lines



Source: RIR

Double Pseudo-Generator Injection Analysis

In the double pseudo-generator injection analysis under the same summer peak conditions, one pseudo-generator is always located at Midway while the second generator moves between Round Mountain, Table Mountain, and Tesla. For example, the Midway generator is 1,000 MW. A second generator is temporary installed at Round Mountain, then Table Mountain, and finally at Tesla. In each case, a new power simulation is completed. The size of the generator varies from 1,000 to 2,000 MW as shown in the table.

Double Injection Analysis Results on 500 kV Lines

Table 14 shows the results for the double injection analysis for the 500 kV lines. The same 500 kV lines are overloaded in the double injection as in the single injection analysis. However, in the double injection, all four lines are overloaded in all scenarios.

Table 14: Double Generator Injection Analysis of the 500 kV Network Under Summer Peak Conditions

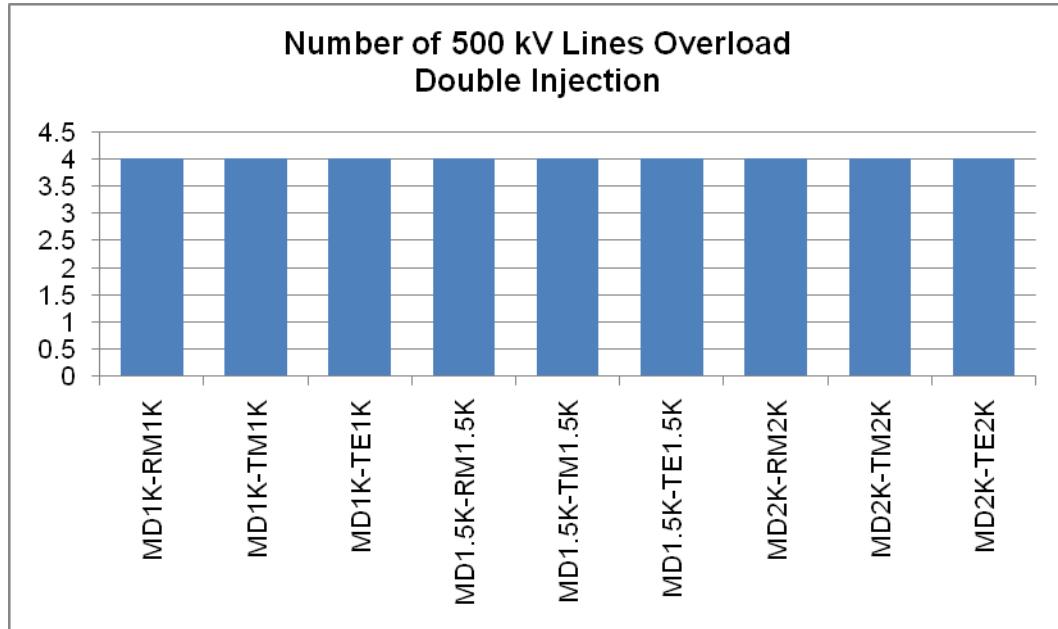
500 kV Lines		MW Injection (MW)	% loading of Limit B Contingency Rating			
			Line 1	Line 2	Line 3	Line 6
		Range of loadings (%)	103-160	107-189	102-164	103-119
Midway at 1000	Round Mountain	1000	X	X	X	X
	Table Mountain	1000	X	X	X	X
	Tesla	1000	X	X	X	X
Midway at 1500	Round Mountain	1500	X	X	X	X
	Table Mountain	1500	X	X	X	X
	Tesla	1500	X	X	X	X
Midway at 2000	Round Mountain	2000	X	X	X	X
	Table Mountain	2000	X	X	X	X
	Tesla	2000	X	X	X	X

Source: RIR

Figure 11 and Figure 12 show the same results but in graphical form. Figure 11 shows the number of 500 kV lines that overload under double injection under summer peak conditions. As shown, the four lines overload in all scenarios. The injection at two different substations makes the labeling difficult on the graph. The injections have been abbreviated to:

- MD is Midway
- RM is Round Mountain
- TM is Table Mountain
- TE is Tesla
- 1K is 1,000 MW
- 1.5K is 1,500 MW
- 2K is 2,000 MW

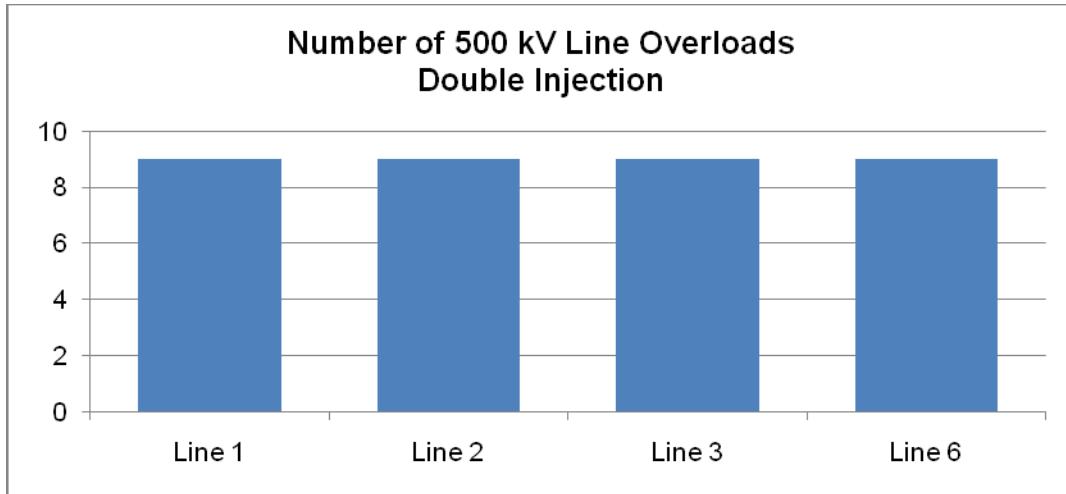
Figure 11: Number of 500 kV Lines That Are Overloaded Under Double Injection Under Summer Peak Conditions



Source: RIR

Figure 12 shows that the four 500 kV lines are overloaded in all nine scenarios.

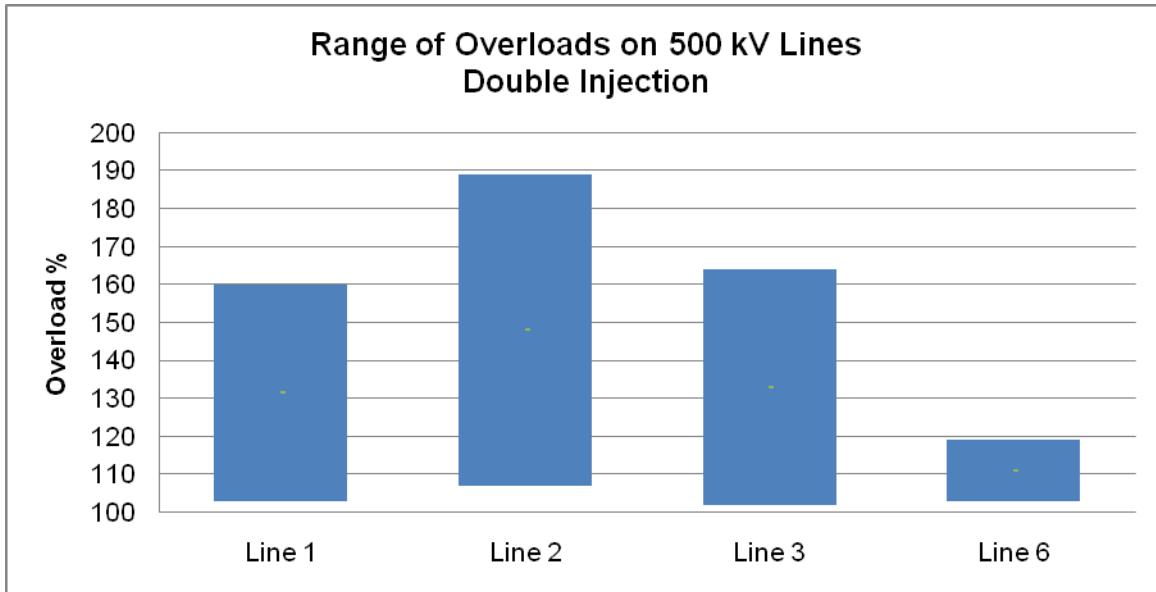
Figure 12: Number of Times a 500 kV Line Becomes Overloaded Under Summer Peak Conditions



Source: RIR

The initial conclusion after analyzing Figure 11 and Figure 12 is that all four 500 kV lines need to be upgraded. However, Figure 13 shows the range of overloads on each of the 500 kV lines. Line 6 overload is lower than the other three lines but occurs across all scenarios. Further analysis may reveal other alternatives than the line upgrade.

Figure 13: Range of Overloads for 500 kV Lines Double Injection Under Summer Peak Conditions

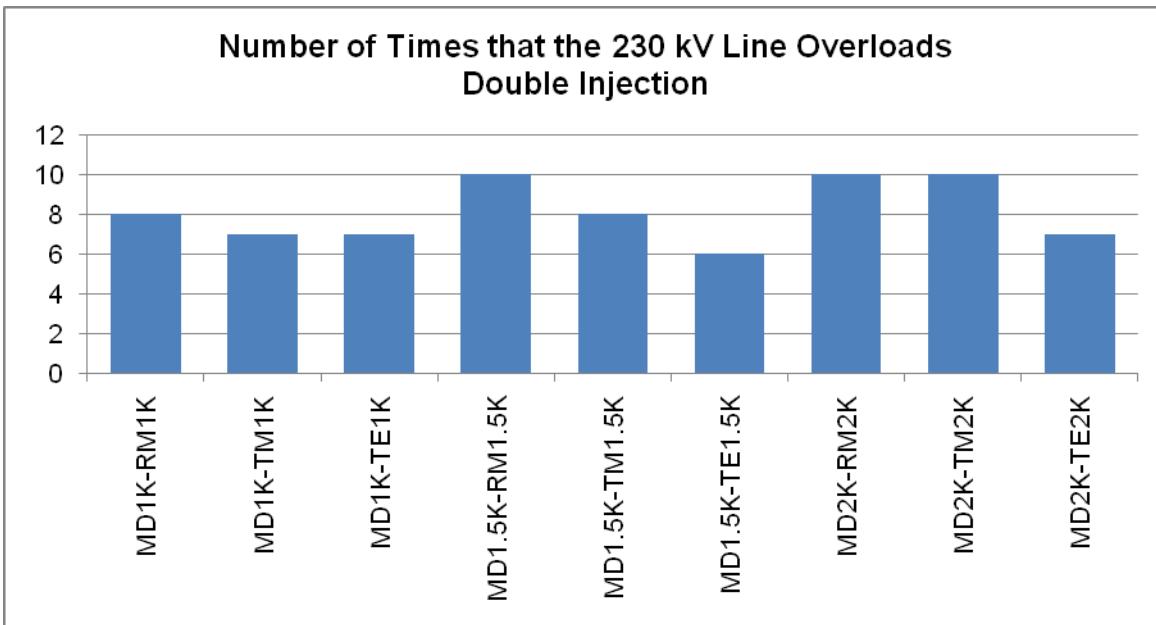


Source: RIR

Double Injection Analysis of 230 kV Lines

In the double injection analysis under the same summer peak conditions, there are a maximum of ten 230 kV lines that overload at any one simulation. Table 15 and Figure 14 show the number of 230 kV lines that overload in each of the nine scenarios.

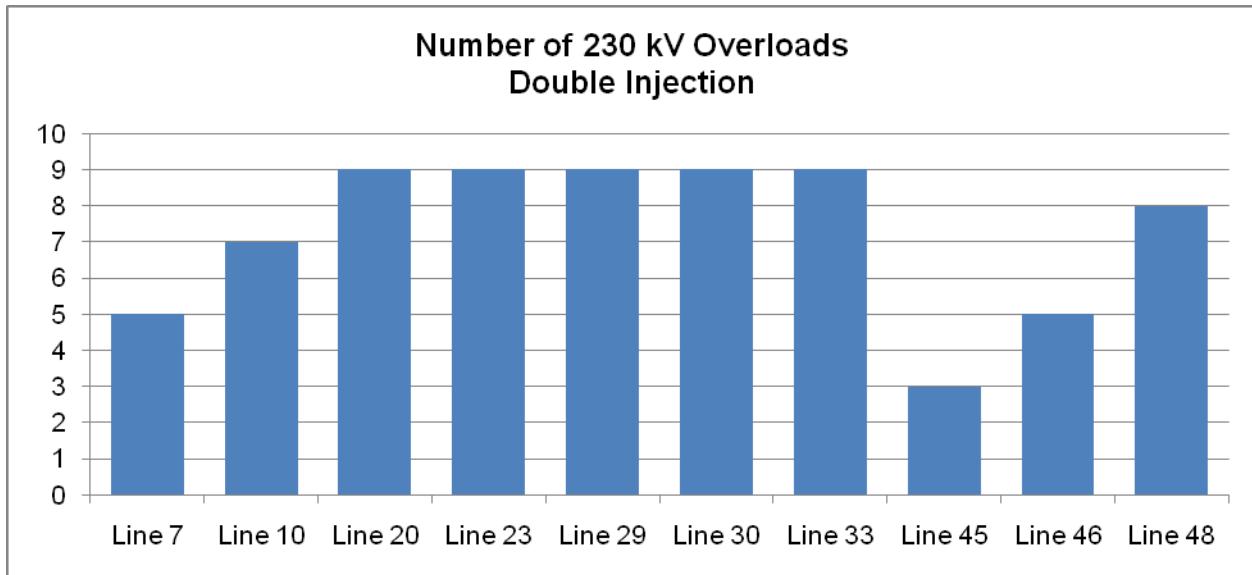
Figure 14: Number of 230 kV Line Overloads Under Double Injection Under Summer Peak Conditions



Source: RIR

Figure 15 shows the number of times each 230 kV lines is overloaded. Out of a total of nine scenarios, five 230 kv lines overload in all nine scenarios. One 230 kV line overloads in eight of the nine scenarios.

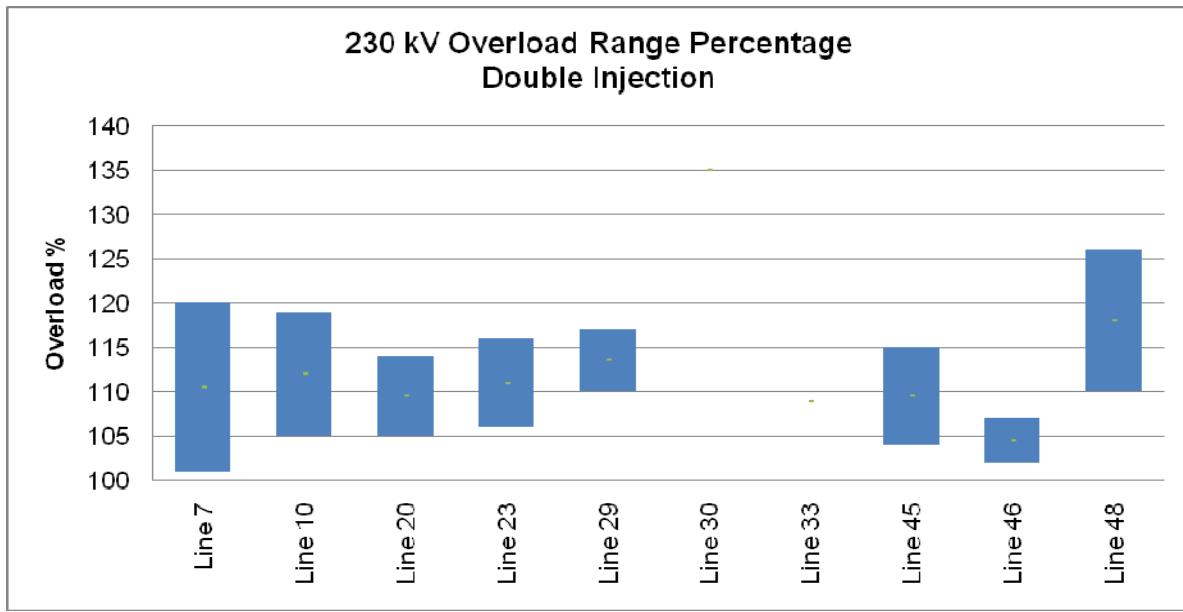
Figure 15: Number of Times That a 230 kV Line Overloads Under Double Injection Under Summer Peak Conditions



Source: RIR

Figure 16 shows the range of loadings in percent under Limit B rating. The range of loadings as a percentage of Limit B is significantly different for the lines.

Figure 16: Range of 230 kV Overloads Under Summer Peak Conditions



Source: RIR

Table 15: Double Generator Injection Analysis of 230 kV Network Under Summer Peak Conditions

		% of Loadings of Limit B Contingency Rating									
230 kV Lines		Line 7	Line 10	Line 20	Line 23	Line 29	Line 30	Line 33	Line 45	Line 46	Line 48
	Range of loadings %	101 - 120	105 - 119	105 - 114	106 - 116	110 - 117	135 - 135	109 - 109	104 - 115	102 - 107	110 - 126
Midway at 1000	Round Mountain	X	X	X	X	X	X	X			X
	Table Mountain		X	X	X	X	X	X			X
	Tesla		X	X	X	X	X	X			X
Midway at 1500	Round Mountain	X	X	X	X	X	X	X	X	X	X
	Table Mountain	X	X	X	X	X	X	X			X
	Tesla			X	X	X	X	X		X	
Midway at 2000	Round Mountain	X	X	X	X	X	X	X	X	X	X
	Table Mountain	X	X	X	X	X	X	X	X	X	X
	Tesla			X	X	X	X	X		X	X

Source: RIR

Reliability Analysis of Pseudo Injection

Figures 5 through 15 present an analysis of the number and magnitude of the 500 kV and 230 kV transmission line overloads under summer peak conditions. However, there still needs to be an analysis on the overall system reliability of the system under a number of different system conditions when injections are made at different points of interconnection. For each of the single and double injection scenarios in this chapter, BEW calculated a reliability index (WTLR) as shown in Table 16 and Figure 17 and Figure 18. A positive WTLR indicates decreases in system reliability.

For each scenario, a set of N-1 contingencies produce a list of overloaded transmission elements. The study considers all contingent outages of single transmission lines and single transformers, and measured contingency overloads only on non-radial transmission elements in California. The simulations incorporated linear approximations of post-contingent conditions to reduce simulation runtime. The linear approximations use flow sensitivities to estimate changes in real power flows and did not evaluate reactive power flows.

The percent overload of the element is weighted by the number of outage occurrences. For a particular line outage, or contingency there are overloaded elements. Each overload element percentage is subtracted by 100% and summed. This value is multiplied by the line rating (MVA) to achieve the Aggregated Mega Watt Contingency Overload (AMWCO) value for that line outage. All of the individual AMWCO values are summed to achieve a System AMWCO value. The delta AMWCO is the difference between the system AMWCO for the base case and each new renewable case. Delta AMWCO is therefore a transmission reliability index, with a unit of megawatts.

If the delta AMWCO is divided by the megawatt of resources added, then an index per MW injected can be determined. The Weighted Transmission Loading Relief (WRTR) is the change in System AMWCO per MW of resource added. Thus, WTLR measures the impact of resources on system security. Negative WRTR indicates an improvement in system security.

$$WTLR = \frac{AMWCO_{renewable} - AMWCO_{base}}{MW_{renewable}}$$

It should be noted that under double pseudo injection, the total injection is divided equally between Midway and the other substation. For example, The Midway and Round Mountain pseudo-injection at 1,000 MW has 500 MW injection at each of the two substations.

For the single pseudo injection, the optimal substations to inject renewable generation under summer peak conditions are directly at the Midway and Tesla substations. These two substations have the lowest WTLRs from 1,000 to 4,000 MW. The injection limit at Table Mountain is 1,000 MW while Round Mountain is 2,000 MW.

For the double injection analysis, the best combination is installing half of the generation at Midway and the other half at Tesla from 1,000 MW through 4,000 MW. The WTLR numbers are high but could be solved with a few strategically located upgrades. After about 2,000 MW pseudo injection with half at Midway and the other half at either Round Mountain or Table Mountain result in a high WTLR.

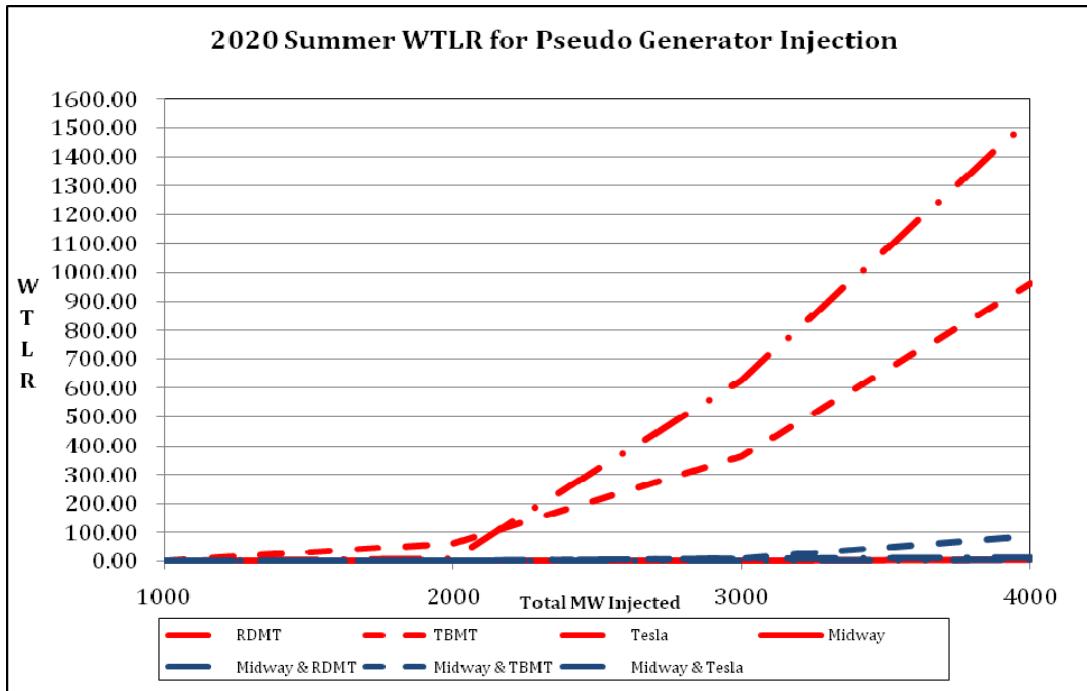
Table 16: Comparison of Pseudo Injection WTLR Values

Total Injection MW	Round Mountain	Table Mountain	Tesla	Midway	Midway and Round Mountain	Midway and Table Mountain	Midway and Tesla
1000	1.24	1.03	0.85	1.23	0.88	0.68	1.05
2000	7.98	62.15	0.75	1.07	3.04	3.23	0.93
3000	624.49	362.21	3.03	2.26	7.93	8.02	2.42
4000	1532.25	962.37	6.22	4.37	13.23	88.46	5.09

Source: RIR

Figure 17 displays the results from Table 16 in graphical form. For the summer peak condition studied, the worst WTLR occur when single injection is at Round Mountain and Table Mountain. Since it is unlikely that all of the future renewable energy needs will occur at one single substation, these are not the optimal locations for injecting large quantities of renewable energy.

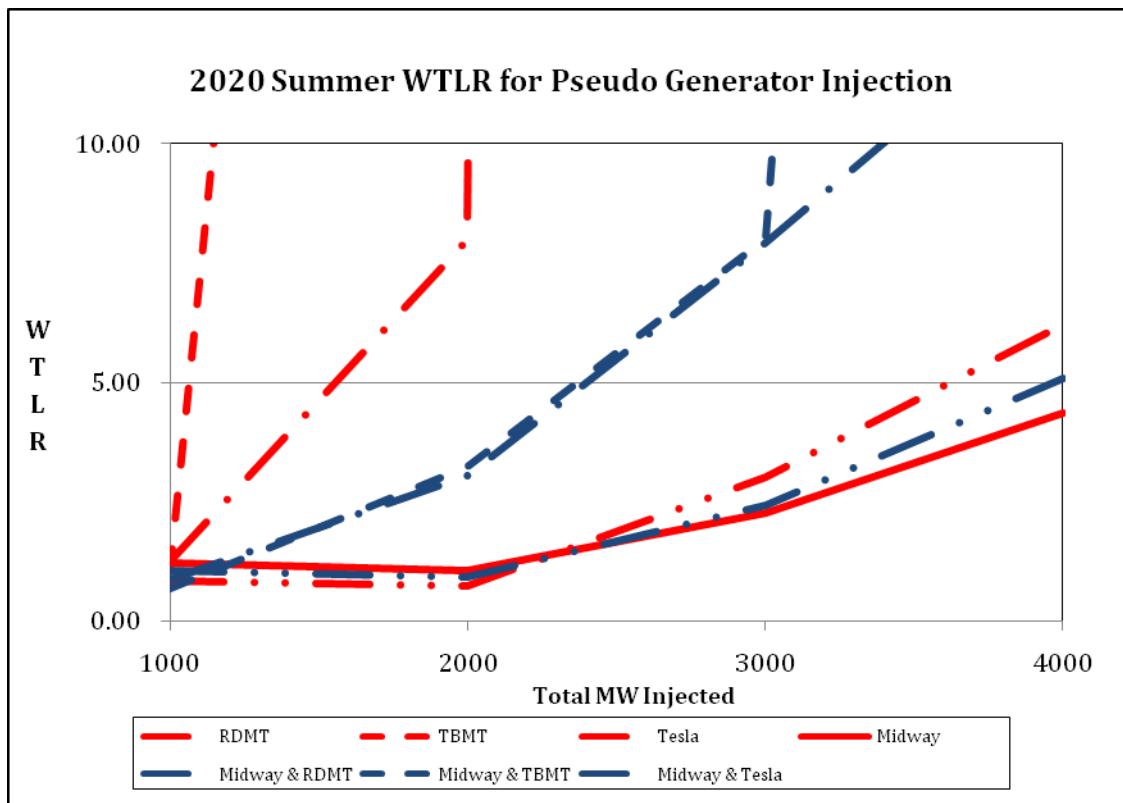
Figure 17: 2020 Summer Pseudo Injections WTLR at Full Scale



Source: RIR

In Figure 18, the research team further investigated the psuedo-injections of scenarios where the maximum WTLR was limited to 20. The most optimal injection options do not have either Round Mountain or Table Mountain as an injection site. The best injection sites have Midway and Tesla as single injection locations or Midway and Tesla as double injection locations for the summer peak condition studied.

Figure 18: 2020 Summer Pseudo Injections WTLR at Modified Scale



Source: RIR

Conclusions of the Pseudo-Generator Injection Analysis

The number of lines that overload under single injection and double injection are almost the same. The overload percentages of the lines vary considerably depending on the location of the pseudo generation and the injected megawatts. For the 500 kV line overloads, Table 17 shows that the same four lines are overloaded and should be considered for further detailed analysis.

Table 17: Comparison of 500 kV Overloads Between Single and Double Injection

Line #	Single Injection	Double Injection
1	X	X
2	X	X
3	X	X
6	X	X

Source: RIR

In Table 18, the number of 230 kV lines that overload under single and double injection are almost identical. Out of the fourteen (14) 230 kV lines, 11 are overloaded in both injection analyses.

Table 18: Comparison of 230 kV Overloads Between Single and Double Injection

Line #	Single Injection	Double Injection
7	X	X
10	X	X
20	X	X
23	X	X
24	X	
28	X	
29	X	X
30	X	X
33	X	X
45	X	X
46	X	X
48	X	X
49	X	X
54	X	
TOTAL	14	11

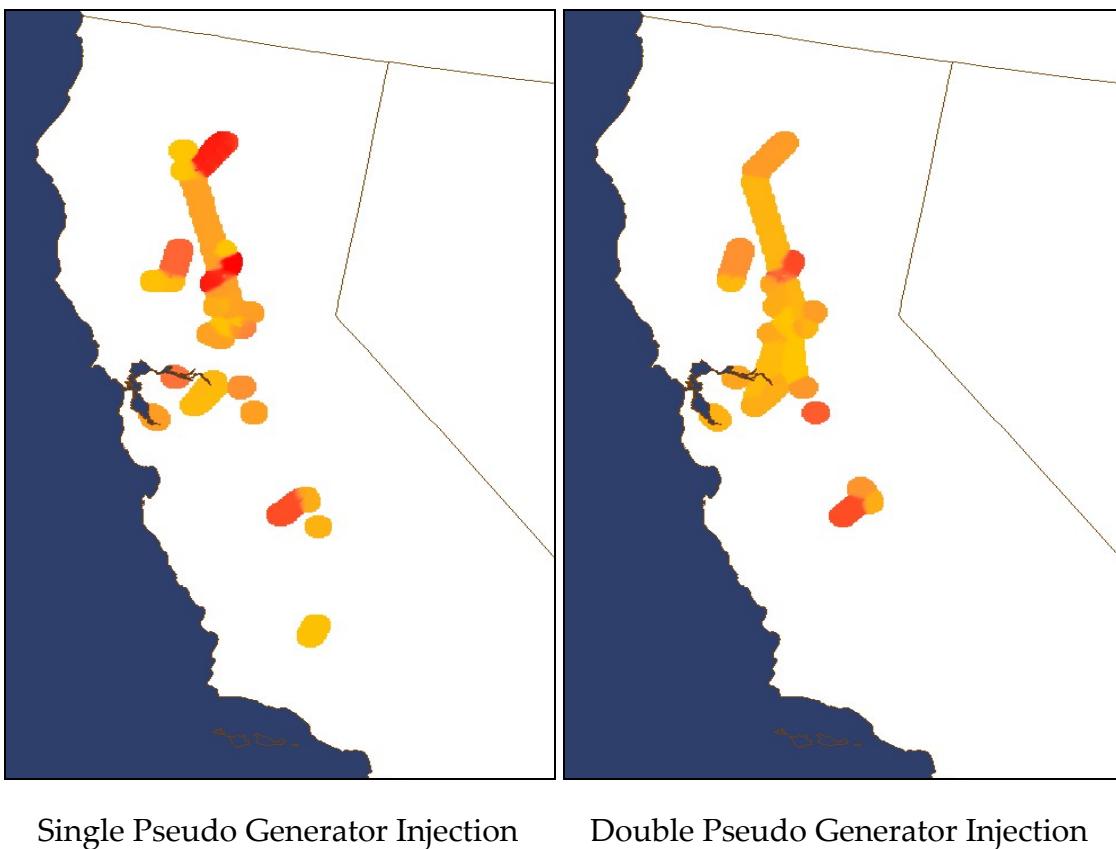
Source: RIR

The calculation of the WTLRs for the different pseudo injections is very valuable in selecting potential locations for interconnecting new generation. For this RIR study, the injection analysis is limited to interconnecting to one or more of the existing substations on the 500 kV grid. However, the injection analysis can be used to study new potential locations that require new substations and new transmission lines. For example, the injection analysis could be used to study a new substation in the west side of Northern California that connects to the grid at a new interconnection point.

The pseudo-generator injection analysis works extremely well to easily determine the impacts of injected generation at potential interconnection points. The analysis is completed without regard to actual configuration of the resource and considers only that one point in time in the power flow simulation. In the next phase of the “least regrets” transmission planning, the overloads highlighted in the pseudo injection analysis serves as the base to begin solution analyses.

Figure 19 below displays the 230 kV and 500 kV transmission overloads for both single and double pseudo-generator injection for the summer peak condition. Ignoring the color variances, the shapes are identifying the general location of the transmission overloads.

Figure 19: Location of Transmission Line Overloads for Pseudo Injection Under Summer Peak Conditions



Source: RIR

CHAPTER 5:

Scenario Development

The pseudo injection investigation shows that the location and combination of the power injection can have significant impact on the power flow and facility loadings. The next step is to expand the investigation to include different renewable resource scenarios and different system conditions.

Renewable Resource Potentials

The potential MW of available renewable resources is first determined by area to begin developing renewable resource scenarios for the RIR study. Three white papers (developed under the Energy Commission PIER Program) were used to obtain potential MW of geothermal, solar, and wind (CEC-500-2005-070, CEC-500-2005-072-D, and CEC-500-2005-071-D) for this study. From each report, the total MW capacity for each renewable resource is determined for each county in California. Table 19, shown below, is a summary of the potential MW of renewables for analysis in the RIR study.

Table 19: Potential RIR Renewable MW Capacity

County	Wind (MW)	Concentrated Solar (MW)	Geothermal (MW)
Alameda	173		
Alpine	733		
Amador	11		
Butte	11		
Colusa	12		
Contra Costa	40		
Del Norte	177		
El Dorado	305	446	
Fresno	337		
Glenn	4		
Humboldt	991		
Imperial	1,460	220,244	2,488
Inyo	5,155	101,581	355
Kern	9,311	127,029	
Lake	8		43
Lassen	440	7,376	8
Los Angeles	5,236	74,233	
Madera	124		

County	Wind (MW)	Concentrated Solar (MW)	Geothermal (MW)
Marin	154		
Mariposa	6		
Mendocino	50		
Merced	60		
Modoc	730	56	37
Mono	2,732	12,055	111
Monterey	88		
Napa	7		25
Nevada	33	149	
Orange	50		
Placer	89	98	
Plumas	207	1,603	
Riverside	5,397	127,161	
San Benito	1		
San Bernardino	7,486	381,159	48
San Diego	3,249	7,687	
San Joaquin	1		
San Luis Obispo	27		
San Mateo	20		
Santa Barbara	2,911	290	
Shasta	693		
Sierra	191	194	
Siskiyou	1,297		211
Solano	310		
Sonoma	48		1,400
Sutter	1		
Tehama	28		
Trinity	130		
Tulare	548		
Tuolumne	323		
Ventura	1,209		5
Yolo	3		
TOTAL	52,607	1,061,361	4,731

Source: CEC

Wind, solar, and geothermal megawatt potential are mapped onto a California county map. Once mapped, counties are grouped into areas. The prefixes W (wind), S (solar), and G (geothermal) are used to identify each area with a numerical suffix. Each renewable resource has renewable potential in different counties, meaning different areas are assigned for wind, geothermal, and solar. For example, counties that are in area G1, can be different for counties in area W1 or S1. Table 20 below lists the counties for each renewable area.

Table 20: Renewable Area and Corresponding Counties

Solar Area	Counties
S1	Modoc, Lassen, Plumas
S2	Sierra, Nevada, Placer, El Dorado
S3	Mono, Inyo
S4	Kern
S5	Santa Barbara, Ventura, Los Angeles, Orange, San Bernardino, Riverside
S6	San Diego, Imperial
S7	Nevada Import
S8	Arizona Import
S9	Fresno, Kings, Tulare
S10	San Luis Obispo
Wind Area	Counties
W1	Del Norte, Siskiyou, Humboldt, Trinity
W2	Modoc, Shasta, Lassen, Tehama, Butte, Plumas
W3	Mendocino, Sonoma, Lake, Glenn, Colusa, Napa, Yolo, Solano, Sacramento
W4	Sutter, Yuba, Sierra, Nevada, Placer, El Dorado, Amador, Calaveras, Alpine
W5	Marin, San Francisco, Contra Costa, San Joaquin, San Mateo, Alameda, Santa Cruz, Santa Clara, Stanislaus, Merced, Monterey, San Benito, Kings, San Luis Obispo
W6	Tuolumne, Mariposa, Madera, Fresno, Tulare
W7	Kern
W8	Oregon Import
W9	Nevada Import
W10	Santa Barbara, Ventura, Los Angeles, Orange, San Bernardino, Riverside
W11	San Diego, Imperial
W12	Mono, Inyo
Geo Area	Counties
G1	Siskiyou, Modoc, Lassen
G2	Sonoma, Lake, Napa
G3	Mono, Inyo
G4	Kern
G5	Oregon Import
G6	Nevada Import
G7	Santa Barbara, Ventura, Los Angeles, Orange, San Bernardino, Riverside
G8	San Diego, Imperial
G9	Utah Import

Source: RIR

Renewable potential data is collected from two additional sources, RETI Phase 1B Draft Resource Report and California ISO's Interconnection Queue (as of November 10, 2008, see Appendix D), to compare the RIR renewable potential from the Energy Commission white paper reports, and develop additional scenarios.

Table 21: Total Summary for Renewable Potential

Total Summary	Geothermal	Solar	Wind
RIR	7,081	1,063,332	47,431
RETI	3,458	447,551	50,302
California ISO Queue	185	38,079	12,561

Source: RIR

Table 21 shows the RIR MW are significantly higher for geothermal and solar resources, doubling that of RETI, and 25 times the California ISO queue MW. The wind potential difference is close between RIR and RETI, while both are still significantly higher than the California ISO interconnection queue. The initial RETI values in the table above differ from the renewable potential summary for the RETI Phase 2 report values. In Phase 2, RETI is approximating 2,791 MW for geothermal, 61,417 MW of solar, and 19,131 MW of wind.

Figure 20, Figure 21, and Figure 22 below represent the areas for potential solar, geothermal, and wind resources from the Energy Commission reports that form the basis for the RIR study. Renewable potential from the RETI Phase 1B report as well as renewable potential from the California ISO generation queue are added to the areas that coincide with the renewable potential from the Energy Commission reports. The value outside parenthesis is the RIR renewable potential. The renewable potential for RETI and California ISO queue is designated with their respective heading followed by the MW potential. Table 22 below is a summary comparing the renewable potential from RIR, RETI, and California ISO queue. The diversity of the renewables potentials underlines the uncertainty and the necessity of investigating a number of resource scenarios.

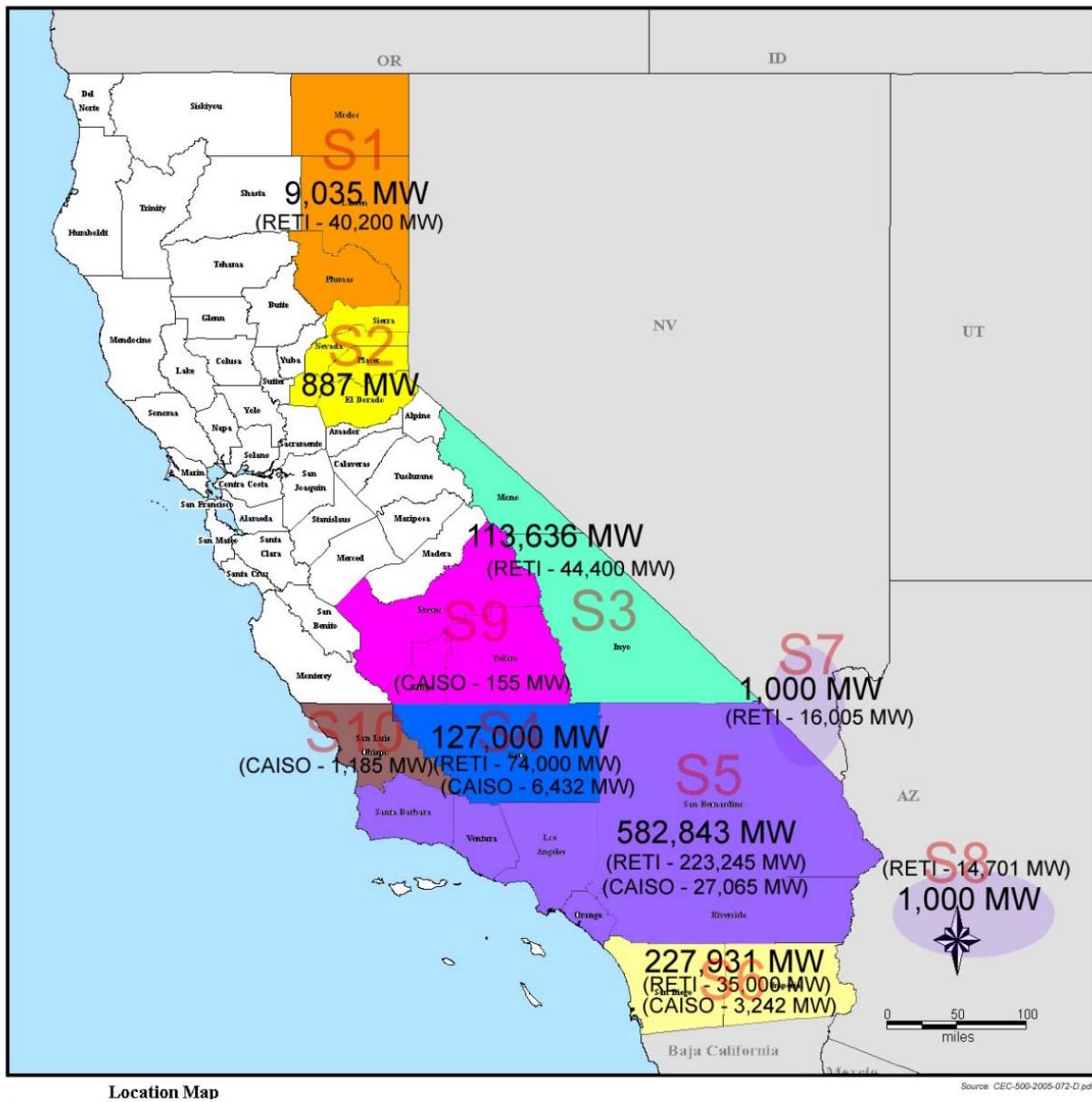
Table 22: Geothermal, Solar, and Wind Renewable MW Potential for RIR, RETI, and California ISO Queue

Geothermal	G1	G2	G3	G4	G5	G6	G7	G8	G9			
RIR	256	1,468	466		250	1,100	53	2,488	1,000			
RETI	333	135		72	520	964		1,434				
California ISO		140	45									
Solar	S1	S2	S3	S4	S5	S6	S7	S8	S9	S10		
RIR	9,035	887	113,636	127,000	582,843	227,931	1,000	1,000				
RETI	40,200		44,400	74,000	223,245	35,000	16,005	14,701				
California ISO				6,432	27,065	3,242			155	1,185		
Wind	W1	W2	W3	W4	W5	W6	W7	W8	W9	W10	W11	W12
RIR	2,595	2,109	442	1,363	537	1338	9,311	2,000	2,000	25,736	4,709	7,887
RETI	297	2,311	768		476		5,844	33,799		6,807	1,128	367
California ISO	50	901	1,396	38	241		5,731			4,204	837	

Source: RIR

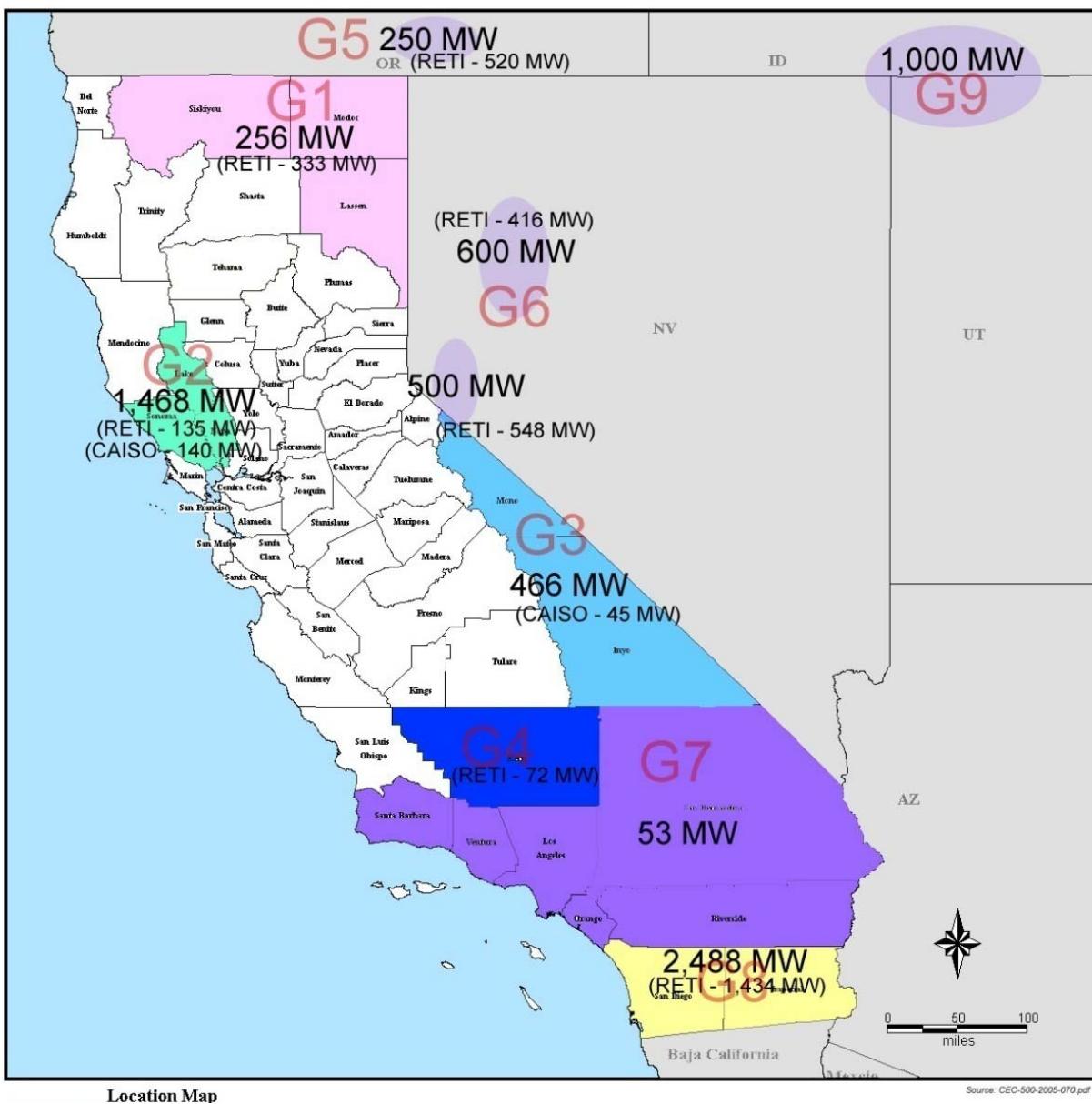
In Table 22, the cells highlighted in YELLOW are resources that flow from the Pacific Northwest and northern Nevada through the California Oregon Intertie (COI) as well as from the areas in the northern counties. The cells highlighted in ORANGE are resources that flow from Southern California and the Desert Southwest over the lines connecting Midway to Southern California as well as from areas surrounding Midway substation. Lastly, the cells that are not highlighted are resources dispersed within Northern California.

Figure 20: RIR, RETI, and California ISO Queue Concentrated Solar Renewable MW Potential



Source: RIR

Figure 21: RIR, RETI, and California ISO Queue Geothermal Renewable MW Potential



Source: RIR

Figure 22: RIR, RETI, and California ISO Queue Wind Renewable MW Potential



Source: RIR

Development of Ten Renewable Resource Scenarios

Based on the Energy Commission reports, to achieve the PRS of 33 percent by 2020, the additional energy requirement is projected to be 19,064,000 megawatt hours. Each scenario is developed by inputting estimated MW values into Table 23 below and calculating the estimated annual energy in MWh. The amount of MW capacity to be installed to realize the additional renewable energy by 2020 is estimated based on the renewable technology, area of development, and delivery point of the resource. The rows highlighted in YELLOW are resources that flow from the Pacific Northwest through the California Oregon Intertie (COI) as well as from the areas in the northern counties. The rows highlighted in ORANGE are resources that flow from Southern California and the Desert Southwest over the lines connecting Midway to Southern California as well as from areas surrounding Midway substation. Lastly, the rows that are not highlighted are resources dispersed within Northern California. The energy in MWh for each location is calculated as installed capacity in MW multiplied by the capacity factor multiplied by 8,760 hrs/year. Afterward, the MWh column is summed and the aggregated renewable energy value can be compared to the 33% renewable energy target.

Table 23: Scenario Development Worksheet

Location	Resource	Installed MW	Max MW	C.F. %	MWh
Medicine Lake Telephone Flat	Geothermal		175	100%	
Geysers	Geothermal		400	100%	
G-1	Geothermal		256	100%	
G-2	Geothermal		1,468	100%	
G-3-G4	Geothermal		466	100%	
G-5	Geothermal		250	100%	
G-6	Geothermal		1,100	100%	
Fire Threat	Biomass		132	100%	
Urban, Agr, Veg	Biomass		363	100%	
Solano	High Wind		275	25-60%	
Altamont	High Wind		132	25-60%	
W-1	High Wind		2,595	25-60%	
W-2	High Wind		2,109	25-60%	
W-3	High Wind		422	25-60%	
W-4	High Wind		1,363	25-60%	
W-5	High Wind		537	25-60%	
W-6	High Wind		1,338	25-60%	
W-7/10/11/12	High Wind		47,643	25-60%	
W-8	High Wind		2,000	25-60%	
W-9	High Wind		2,000	25-60%	
Contra Costa	Low Wind		28	25-60%	
Siskiyou	Low Wind		41	25-60%	
Yolo	Low Wind		3	25-60%	
S-1	CSP		9,035	0-100%	
S-2	CSP		887	0-100%	
S3-S4/5/6	CSP		1,051,410	0-100%	
Total					
<i>33% Requirement</i>					19,064,000

Source: RIR

Twelve initial scenarios are developed by BEW Engineering in the first round of analysis using the RIR renewable potential as described in an earlier section. Four scenarios are removed due to similarities among the remaining scenarios. The remaining eight scenarios are presented to both CAT members and stakeholders. An additional ninth scenario is added later at the request of stakeholders. The California ISO Queue renewable potential is added as a tenth scenario. The RETI renewable potential was added as a placeholder but not used for any scenarios for this RIR study because the RETI renewable resources results were not available in time to be included in the base case development. However, RETI Phase 2A resources were examined and the expected impacts on the transmission system were found to be similar to two of the scenarios (Scenarios 7 and 10) already included in RIR. See Table 25 for a comparison of the summary of the resource scenarios.

Table 25 lists the final 10 scenarios selected for analysis. During CAT meetings, it is decided to begin the analysis by selecting a few of the scenarios. “Bookends” of the 10 scenarios are the two

scenarios that stress the system most. Scenarios 7 and 8 are selected as the bookends since Scenario 7 has high renewable generation at Midway and Scenario 8 high renewable generation at the COI delivery point. Two additional scenarios are selected that fall in the average stress category between the two extreme bookends selected. Scenario 6 and Scenario 10 are chosen for this analysis. Scenario 6 assumes an even dispersement of renewable across Northern California whereas scenario 10 is the California ISO mix for distributing the renewable generation across California.

The base cases, described in Chapter 3 for spring, summer and fall, simulate scenarios that have different renewable penetrations, locations, and sizes. The selection of the study scenarios is completed over a series of iterations. A number of scenarios are created for analysis in Northern California by BEW. Scenarios are narrowed down by removing the similar scenarios and the remaining scenarios are shown to the CAT for review. These are detailed in Table 25. For each penetration scenario, potential transmission upgrade options are proposed by the CAT, discussed in Chapter 6.

For each season, the 10 cases with multiple transmission upgrade options are simulated under normal (all facilities in service or NERC Category A) conditions and single contingency (N-1 or NERC Category B) conditions. The contingency analysis is specifically configured to simulate outages of lines 230 kV and above, and generators greater than 100 MW. Each season (summer, spring, and fall) has a coincident renewable generating factor. This is the projected MW generation coincidental with the time period and system condition represented in the power flow simulation. The coincident renewable generation is always less than or equal to the installed MW capacity. The coincident is changed to test the sensitivity for potential transmission overloads. Coincident renewable capacity is the projected capacity to be generating at the load level and time period simulated in power flow case. For example, summer peak case represents the system condition at the time of the system peak, spring peak case represents system conditions expected at the time of the highest spring peak demand and fall case represents system conditions around the lowest load level during fall off-peak period. The generation is scaled to the coincident renewable capacity for each season (Table 24). Geothermal and biomass are considered base-loaded and have a capacity factor of 100%. Wind units have a capacity factor of 25% in the summer and 60% in Spring and fall. Solar units have a capacity factor of 58% for summer and spring. However, since the fall case models an off peak time period, it is assumed that there is no solar available.⁸

⁸ It is recognized that off-peak periods include night times, as well as afternoons on weekends, when solar energy is available. However, the RIR study models night period to capture the wider renewable resource diversity.

Based on the topology of the transmission system, injection points were selected in each area where the additional renewable resources would likely interconnect. For renewable resource areas close to the existing system, these injection points selected are primarily existing 230 kV and 500 kV busses. For resource areas where there is no existing transmission facilities directly connecting to the Northern California transmission system, new transmission facilities are assumed to be built to reach the existing transmission system. For resource areas primarily served by 115 kV transmission facilities, the existing transmission facilities were assumed to be upgraded to 230 kV or 500 kV, depending on the amount of new resources assumed for the area for that resource scenarios. The proposed injection points for geothermal, wind, and solar resources are in Appendix A. Renewable resources that were identified to be in these areas (Figure 20, Figure 21, and Figure 22) are injected at select buses. Detailed locations are listed in Appendix A.

Table 24: Generation Capacity Factor Depending on Season

	Summer	Spring	Fall
Geothermal	100%	100%	100%
Biomass	100%	100%	100%
Wind	25%	60%	60%
Solar	58%	58%	0%

Source: RIR

Currently there are 10 scenarios. The scenarios are detailed on the RIR website (<http://www.pge.com/rir/>), ensuring everyone has the same data sets. The Scenarios are outlined in Table 25.

Table 25: Scenarios for Each Season

Scenario	Configuration
Scenario 1	High Midway Wind and Solar with Geothermal
Scenario 2	High COI Geothermal Northern CA and NV
Scenario 3	Dispersed throughout Northern California
Scenario 4	Minimum COI and No Midway
Scenario 5	Majority Geothermal
Scenario 6	Even Distribution with Geothermal
Scenario 7	High Midway wind and solar; Minimum Geothermal
Scenario 8	All COI
Scenario 9	Majority COI and Midway – Stakeholder Suggestion
Scenario 10	California ISO Mix

Source: RIR

Table 26 summarizes the MW installed for each of the 10 resource scenarios and the type of generation. This summary also offers a comparison of the resources in RETI Phase 2A Report, adjusted to reflect the portion of additional renewables needed for Northern California entities to meet their renewables target of 33%.

Table 26: MW for Each Scenario and Generation Type for Northern California

Renewable Resource Scenario	Geothermal	Biomass	High and Low Wind	CSP Solar	Total Installed (MW)	Total Expected Energy (GWh/yr) for N CA
Scenario 1	1,325	-	1,979	1,000	4,304	19,150,148
Scenario 2	2,245	-	479	-	2,724	19,176,428
Scenario 3	745	495	2,629	400	4,269	19,109,852
Scenario 4	1,075	495	2,129	-	3,699	19,144,892
Scenario 5	1,775	495	479	-	2,749	19,315,712
Scenario 6	925	495	2,129	500	4,049	19,144,892
Scenario 7	600	-	3,000	2,000	5,600	19,184,400
Scenario 8	725	-	3,500	1,000	5,225	19,425,300
Scenario 9	450	-	4,430	1,250	6,130	20,862,816
Scenario 10	185	-	4,101	2,400	6,686	20,427,181
RETI Phase 2A ⁹	229	32	1570	5040	6870	19,064,082

Source: RIR

⁹ RIR is based on meeting 100% of the RPS goal. For purposes of developing a conceptual transmission plan that addresses uncertainties in the location of renewable resource development, RETI planned for renewable resource additions much higher than required to meet the RPS goal. To be directly comparable, RETI resources were adjusted assuming that Northern California load is supplied from a pro rata share of renewable resources as indicated in RETI Phase 2A Report to meet RPS of 33% in Northern California.

CHAPTER 6:

Transmission Options

To compliment the scenario analysis, transmission options are developed to accompany each scenario. Twelve transmission options are selected during meetings with CAT members and stakeholder conference calls. The first option (Option A) is no additional transmission upgrades to identify potential transmission problem(s) associated with the 10 resource scenarios. The remaining eleven options contain various transmission line upgrades. Table 27 lists the summary of transmission options used in this study.

CAT selected specific 500 kV line additions for this study to mitigate the potential overloads identified in Option A cases (no transmission addition) for each of the 10 resource scenarios based on past experiences. As such, these transmission additions are among potential transmission corridors being considered or were considered by some of the CAT members. Note that many of the transmission additions are still being investigated and the exact plan of service are not available. For the purpose of developing conceptual transmission projects, this study either models one of the alternatives being studied, where available, or utilizes simplified models. This generalization should not impact the results of this study. The names of some of the termini of the potential new transmission facilities were accordingly changed to represent a general location of the lines or paths to be reinforced.

Initial discussion limited the scenarios to specific transmission options. For example, for Scenario 1, only Options A, B, C, and D are completed because Scenario 1 simulates additional renewable resources mostly located in Southern California, options that add transmission facilities in the northern half of Northern California would not provide significant relief. However, it is decided for consistency purposes, as well as robustness for comparisons, that the remaining Options E through L are also completed. For each scenario, both N-0 (NERC Category A) and N-1 (single contingency or NERC Category B) analysis were performed for each transmission option. Multiple contingencies or N-2 (NERC Category C) contingencies were not performed because the mostly likely transmission plan to resolve such potential overloads would be to install a special protection scheme (SPS) to trip load or generation such that the potential overloads would be no more severe than those due to the single contingencies. SPS design requires detailed project specific information, which is beyond the scope of a conceptual study.

Table 27: Transmission Option Summary

Option	Transmission Options Studied	Upgrade Region
A	No additional transmission reinforcement	
B	C3ET Project	South of Tesla
C	C3ET Project + Cottle - Tesla/Tracy Project	South of Tesla
D	C3ET Project + Cottle - Tesla/Tracy Project + Cottle - Gregg Project	South of Tesla
E	CNC + C3ET	Over Nor. CA
F	CNC Only	North of Tesla
G	Round Mt - Tesla 500 kV + C3ET Project	Over Nor. CA
H	Round Mt - Tesla 500 kV	North of Tesla
I	C3ET Project + Cottle - Tesla/Tracy Project + Cottle - Gregg Project + Round Mt - Tesla 500 kV	Over Nor. CA
J	Round Mt - Tesla 500 kV + CNC	North of Tesla
K	Round Mt - Tesla 500 kV + CNC + Malin – Tracy/Tesla 500kV	North of Tesla
L	Round Mt - Tesla 500 kV + CNC + C3ET	Over Nor. CA

Source: RIR

Transmission Option Details

There are 7 unique transmission projects that individually or combine to create the 12 transmission options to be studied. The options are in line with new high-voltage projects in various stages of planning. The transmission components are discussed in more detail below. The CAT team did not provide 230 kV upgrades except for those associated with upgrading the existing system to allow renewable resources to be delivered to the grid.

No Additional Transmission Reinforcements

Option A

This transmission option determines the overloads without any additional transmission upgrades.¹⁰ A scenario specific renewable generation profile is modeled onto each of the seasonal base cases. This option establishes a baseline so that when a transmission option is introduced in conjunction with the renewable generation profile, the positive or negative effects of the transmission options are analyzed.

C3ET Project¹¹

Included in Options B, C, D, E, G, I, and L

¹⁰ In the base cases, Los Banos – Westley 230 kV line is assumed to be reconducted because that line was identified in PG&E's Assessment Studies to need upgrades. It is also heavily loaded under certain current operating conditions.

¹¹ For the purpose of this study, the alternative to connect Midway Substation to Gregg Substation with a 500 kV double circuit tower line was selected.

- Two 500 kV circuits connected PG&E's Midway 500 kV and Gregg 500 kV buses
- Two 500/230 kV transformers at Gregg.

Cottle to Tesla/Tracy Project

Included in Options C, D, and I

This transmission option reinforced the voltage 115 kV to 500 kV network south of Tesla.

- A new 500 kV circuit connected Cottle (Park Junction) to WAPA's Tracy Substation.
- A 500 kV transformer bridged a connection from Park Junction 500 kV and Park Junction 230 kV.
- Two 230 kV circuits connects MID's Parker Substation to Park Junction.
- Two 230 kV circuits connects Park Junction to Monte 230 kV.
- From Monte 230 kV bus, there is one 69 kV to 230 kV transformer to Monte Tap 69 kV
- From Monte 230 kV bus, there is a double transformer circuit to Monte 115 kV.
- From Monte 115 kV bus, there is a 115 kV circuit to Pioneer 115 kV and a 115 kV circuit to Tuolumne 115 kV.

Cottle – Gregg Project

Included in Options D and I

This transmission option is a 500 kV circuit that bridges the northern terminus of the C3ET Project to Cottle to Tesla/Tracy Project transmission upgrades.

- One 500 kV circuit connects the Gregg 500 kV bus to Park Junction 500 kV bus.

Canada/Pacific Northwest – Northern California Transmission (CNC) Project

Included in Options E, F, J, K, and L

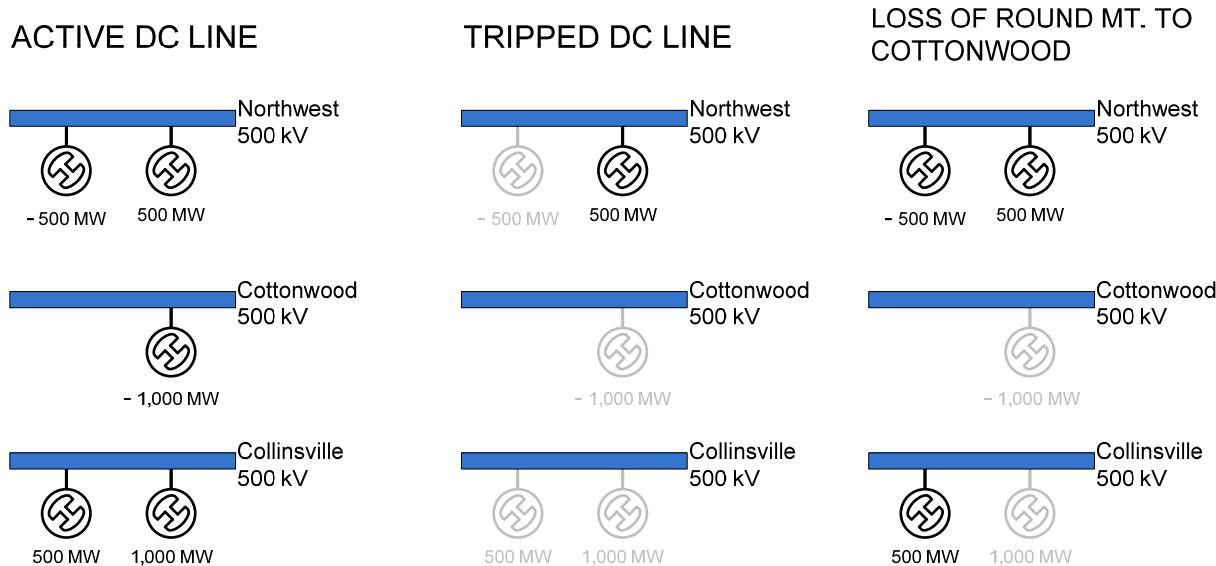
The CNC Project involves the construction of approximately 1000 miles of high-voltage AC (HVAC) and high-voltage DC (HVDC) transmission lines from British Columbia to Northern California and interconnects with five or six existing and proposed substations. For the purpose of this study, this transmission option models potential resources connecting to a 500 kV HVAC to +/- 500 kV HVDC converter in a substation in the Pacific Northwest, a +/- 500 kV HVDC transmission line from this converter station in the Pacific Northwest to PG&E's Collinsville substation with a third +/- 500 kV HVDC termination and a +/- 500 kV HVDC to 500 kV HVAC converter at Cottonwood Substation in the PG&E area. The model includes:

- A +/- 500 kV DC circuit from Round Mt. connected to a new +/- 500 kV DC to 500 kV AC Converter at Cottonwood substation.
- A new +/- 500 kV DC to 500 kV AC Converter at Collinsville and loop the Collinsville 500 kV bus into the Vaca Dixon - Tesla 500 kV line, and a new 500 kV connection between Collinsville and Tracy Substation.
- Collinsville 500 kV bus has a double transformer circuit connected to a new Collinsville 230 kV bus and two new Collinsville – Pittsburg 230 kV lines.
- DC Line Model (see Figure 23):
 - Generators are modeled to simulate a DC line. The generator at the sending end is modeled as a load (or negative generation), and the other generator at the receiving end is modeled as a new renewable resource (positive generation). Both generators negate each other for the entire DC line.
 - Two generators are modeled in the Northwest area. One is modeled as positive generation to simulate the new renewable resources in the Pacific Northwest to be sent to Northern California. The second generator is modeled as load (or negative generation) to simulate the start of the +/- 500 kV DC line section between the Pacific Northwest and Cottonwood.
 - One generator is modeled as a load (negative generation) at the new Cottonwood 500 kV bus, simulating the 500 kV AC to +/- 500 kV DC Converter. This is to mimic the effect of the transmitting 1,000 MW of renewable resources from areas around Northern California and southern Oregon south to Collinsville area over the portion of the +/- 500 kV DC line between Cottonwood and Collinsville.
 - Two generators are modeled as the receiving end of the +/- 500 kV DC line at the Collinsville 500 kV bus. One generator has positive generation of 500 MW that simulates the renewable resources received from the Pacific Northwest, and the second generator has positive generation of 1,000 MW as the renewable resources received from Cottonwood 500 kV.

The renewable generation from the Pacific Northwest is scenario-dependent. When the DC line is modeled, a portion of renewable resources from the Northern California area (in this case 500 MW) is shifted to the Pacific Northwest to maintain the same amount of renewable energy required to achieve the 33% RPS target. Therefore, for this scenario, the alternative of the +/- 500 kV DC line being considered is designed to transfer 500 MW from the Pacific Northwest and 1,000 MW from Round Mt./Cottonwood area to Collinsville. Figure 23 below is a graphical representation on the CNC DC line model in the analysis. On the left, is the +/- 500 kV DC line with all of the facilities in

service (represented with all generators online). The middle, Tripped DC Line models the loss of the entire +/- 500 kV DC line section from Pacific Northwest to Collinsville, including the Converter at Cottonwood. All of the generators, which are part of the model for the DC line, are tripped (grayed out) to show the loss of the DC line except for the generator in the Northwest to simulate the associated Pacific Northwest renewable resources remaining on-line. In this instance, the associated power that was transferred to Collinsville remains on-line in the Pacific Northwest as are the renewable resources in California. For the loss of the 500 kV AC to +/- 500 kV DC Converter at Cottonwood, the 1,000 MW of power can no longer be delivered to Collinsville through the HVDC line. Hence the associated generator at Cottonwood (modeled as a load or negative generation) and at Collinsville (modeled as positive generation) are tripped.

Figure 23: Graphical Representation of Different DC Line Statuses



Source: RIR

Round Mt. – Tesla 500 kV

Included in Options G, H, I, J, K, and L

Substantial transmission upgrades and system changes are part of Round Mt. – Tesla 500 kV option. These options primarily benefit the electric grid north of Tesla.

- 500 kV line from Round Mt. to new Round Mt. 2 500 kV bus north of Round Mt.
- Multisection line from Round Mt. 2 to Olinda 500 kV.

- Multisection line from Olinda to Dillroad 500 kV.
- 500 kV line from Dillroad 500 kV to Tracy 2 500 kV.
- 500 kV line from Tracy 2 to Tracy 500 kV.
- Double transformers from Dillroad 500 kV to Dillroad 230 kV.
- Replaced the two existing 230 kV lines from Rancho Seco to Hedge 230 kV and Pocket 230 kV with two 230 kV lines from Dillroad 230 kV to Hedge 230 kV and Pocket 230 kV.

Fourth COI Line (or Malin-Tesla/Tracy)

Based on the potential overloads to existing facilities, there is an option to include a fourth line connecting COI to Tesla (in addition to the existing California – Oregon Transmission Project and the two 500 kV lines in Pacific AC Intertie). The fourth COI line consists of multisection lines connecting Malin to Round Mt. to Table Mt. to Tesla.

CHAPTER 7:

Power Flow Analysis and Results

N-0 (NERC Category A) and N-1 (NERC Category B) Analysis

The scenarios and options are simulated two ways. Power flow simulations are completed under steady state normal conditions (N-0) and first contingency (N-1) conditions for each resource scenario for the summer peak, spring peak, and fall off-peak cases. N-0 or normal conditions mean all facilities are in service in the system. The N-0 overloads are calculated based on conductor limit A ratings (or Normal Ratings). The N-0 analysis is completed for each resource scenario and transmission option. The overloaded lines are then compiled into a single table for tracking overloaded lines rated 230 kV and above.

The second part of the analysis is based on single contingency (or N-1) conditions. The N-1 contingencies are simulated for each resource scenario and upgrade option, for all generators above 100 MW and all transmission lines 230 kV or greater. Under N-1 conditions, the power flow elements (transmission line, transformer or generator) are temporarily removed from service one at a time and a new power flow simulation is completed. This process is repeated automatically for each element in the power flow case, until all of the individual elements are studied. For an N-1 simulation of the California, up to 5,000 simulations are completed for one scenario. One or more of these individual simulations may cause an overload based on Limit B ratings (or Emergency Ratings) on one or more elements. The percentage overload of the element is weighted by the number of outage occurrences and displayed at the end of the simulation.

Under certain N-1 contingency outages, the power flow may return unsolved power flow cases, indicating that feasible solutions were not achievable for the system and condition simulated. If left unsolved, the results will not accurately reflect transmission line loadings. One or more of the corrective actions below was used to correct unsolvable contingency cases:

- Addition of 230 kV line from Caribou to Table Mt. D
- Under a Cottonwood 500 kV to Round Mt. 500 kV outage, the CNC (DC) line is tripped
- Under the Table Mt. 500 kV to 230 kV transformer bank outage, California Department of Water Resources (CDWR) generation at Thermalito and Hyatt are tripped
- Under the Table Mt. 500 kV to 230 kV transformer bank outage, if tripping CDWR generation is not enough to for the system to arrive at a feasible solution, the new renewable generation at Table Mt. is tripped
- For power flows with voltage stability issues near Malin, synchronous condensers, and capacitor banks were turned on

In order to simplify the result tables, Line numbers (Line #) are used instead of the listing the full from and to substation names. Table 28 below is a key to identify the major substation associated with the unique line number for the power flow results for both N-0 and N-1.

Table 28: Line Numbering Key for Results

Line #	From Substation	To Substation	Nominal Voltage
Line 1	TABLE MT.	VACA DIXON	500
Line 2	ROUND MT.	TABLE MT.	500
Line 4	LOS BANOS	GATES	500
Line 5	GATES	MIDWAY	500
Line 6	MALIN	ROUND MT.	500
Line 7	COTWD_E	ROUND MT	230
Line 8	COTWD_F	BRNY_FST	230
Line 9	BRNY_FST	PIT 1	230
Line 10	CPVSTA	CORTINA	230
Line 11	PIT 3	ROUND MT	230
Line 13	POE	RIO OSO	230
Line 14	RIO OSO	ATLANTC	230
Line 17	FULTON	IGNACIO	230
Line 18	T22_93	FULTON	230
Line 19	LAKEVILLE	T22_93	230
Line 20	STAGG-J2	TESLA E	230
Line 23	EIGHT MI	TESLA E	230
Line 26	PANOCHÉ	MCMULLN1	230
Line 27	PANOCHÉ	GATES	230
Line 29	STOREY 1	GREGG	230
Line 30	GREGG	FGRDN T2	230
Line 31	MCMULLN1	KEARNEY	230
Line 32	BULRD_EC	KEARNEY	230
Line 33	HERNDON	FGRDN T1	230
Line 34	MC CALL	HENTAP2	230
Line 39	GATES	MIDWAY	230
Line 40	TEMPLETN	MORROBAY	230
Line 44	AIRPORTW	COTWDWAP	230
Line 45	COTWDWAP	ROUND MT	230
Line 47	FOLSOM	LAKE	230
Line 48	FOLSOM	ORANGEVL	230
Line 50	KESWICK	AIRPORTW	230
Line 51	OLINDAW	OLINDA	230
Line 52	OLINDAW	COTWDWAP	230
Line 53	OLINDAW	KESWICK	230
Line 59	C.COSTA	LONETREE	230
Line 68	ELKGROVE	RNCHSECO	230

Source: RIR

N-0 Results

After the analyses are completed, the N-0 results from each scenario and transmission option are aggregated and sorted by greatest number of occurrences of potential overloads. To compile a ranking of these lines, the number of times the line appears in each resource scenario and transmission option as overloaded is summed and totaled. In each resource scenario, as detailed in Section 10, twelve transmission options are considered for 10 different scenario profiles. Referring to Table 29 below, the number of times the transmission option is considered through all the scenarios (1 through 10) is detailed in the “*Maximum number of occurrences of potential overloads through all scenarios*” row.

Twelve transmission options are simulated for each of the 10 scenarios. Therefore, the number of possible times a line can be counted as overloaded for each transmission option A through L is 10. The maximum number of occurrences that a specific line can be overloaded through each combination of transmission option and scenario is 120.

The lines are ranked based on this total number; therefore Line 59 is overloaded in all of the scenario for all of the options and Line 6 is overloaded in 79 out of the 120 possible scenario/transmission option possibilities. Line 6, Option B, overloads in 5 of the 10 scenarios and when summed across, makes up 79 out of 120 outcomes. On closer examination by reviewing the locations of renewable resources additions, a number of the overloaded lines appear to be more related to serving load than to the transmission of the additional renewable resources. These are shown in Table 28-a. Potential overloads on these lines will be noted but not be considered in the development of transmission for the potential renewable resources.

Table 28-a: Lines That Are Primarily Related to Load Serving

Line #	From Substation	To Substation	Nominal Voltage
Line 30	GREGG	FGRDN T2	230
Line 33	HERNDON	FGRDN T1	230
Line 48	FOLSOM	ORANGEVL	230
Line 59	C.COSTA	LONETREE	230

Source: RIR

The top 10 line overloads under N-0 conditions is ranked from the worst overloaded line, i.e. the most number of instances of overload through all the scenarios and options, to the least number of instances of overloads through all the scenarios and options. The results for the 2020 Summer Peak are in Table 29. A zero marked in the table (cells are highlighted in green) indicates that the line has not overloaded in any of the scenarios. Cells are highlighted in yellow if the line has more than one overload in Option A (no additional transmission) and only one overload with the corresponding transmission Options. For example, Line 10 under Option A has 2 overloads when all resource scenarios are considered. The number of overloads decreased to one with Options E, F,

or L across all resource scenarios. The corresponding cells are highlighted in yellow. These green and yellow highlights identify the transmission options, which could help decrease the number of overloads for that line for all resource scenarios considered.

Table 29: N-0 Line Overloads for 2020 Summer Peak

Line #	Overload Range %	A	B	C	D	E	F	G	H	I	J	K	L	Total
Line 59	107-121	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 6	100-112	4	5	4	5	8	8	9	9	9	9	0	9	79
Line 10	100-110	2	2	2	2	1	1	2	2	2	0	0	1	17
Line 14	102-107	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 18	119-122	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 19	118-120	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 68	109-109	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 1	104-113	1	1	1	1	0	0	1	1	1	1	0	1	9
Line 13	117-118	1	1	1	1	0	0	1	1	1	0	0	0	7

Source: RIR

Line 59 overloads in the 2020 summer peak base case with no additional generation added. Line 59 is overloaded in all possible scenarios and transmission options (120 out of 120 possible overload instances). As mentioned above the overload on Line 59 will not be used to determine the upgrade needed for interconnecting new renewables because its loading is more load-serving related. The total number of overloads matches the maximum possible number of overload possibilities. The first 500 kV line appearing in the overload rankings is the Line 6. The number of line overloads occurring is 79 out of 120 times, through all the scenarios and options.

Table 30 and Table 31 below are the N-0 overloads for 2020 spring peak and the top 10 most severe overloads for 2020 fall off-peak. Both summer and spring have 10 or fewer unique transmission line overloads over all scenario and transmission options, whereas fall off-peak has more than 10 unique transmission line overloads.

Table 30: N-0 Line Overloads for 2020 Spring Peak

Line #	Overload Range %	A	B	C	D	E	F	G	H	I	J	K	L	Total
Line 59	101-116	8	8	8	8	8	8	7	7	7	8	7	8	92
Line 6	100-113	2	2	2	2	8	8	9	9	9	9	0	9	69
Line 1	102-122	3	3	3	3	0	0	0	0	0	1	0	1	14
Line 18	136-141	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 19	135-140	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 14	100-109	1	1	1	1	1	1	1	1	1	1	0	1	11
Line 13	123-124	1	1	1	1	0	0	1	1	1	0	0	0	7
Line 8	118-123	1	1	1	1	1	1	0	0	0	0	0	0	6
Line 9	117-122	1	1	1	1	1	1	0	0	0	0	0	0	6
Line 11	102-106	1	1	1	1	1	1	0	0	0	0	0	0	6

Source: RIR

Table 31: Top Ten N-0 Overloads for 2020 Fall Off-Peak

Line #	Overload Range %	A	B	C	D	E	F	G	H	I	J	K	L	Total
Line 48	100-122	8	8	9	9	5	6	10	10	10	10	10	10	105
Line 5	101-142	10	6	6	6	5	10	8	10	8	10	10	7	96
Line 47	100-118	0	0	0	0	0	0	2	3	3	5	7	7	27
Line 26	100-105	5	0	0	0	0	5	0	5	0	5	5	0	25
Line 4	100-132	2	2	2	2	2	2	2	2	1	2	2	2	23
Line 27	103-118	2	1	1	1	1	2	1	2	1	2	2	1	17
Line 18	136-140	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 19	136-139	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 40	108-116	1	1	1	1	1	1	1	1	1	1	1	1	12
Line 11	128-133	1	1	1	1	1	1	0	0	0	0	0	0	6

Source: RIR

For the 2020 spring, the top two transmission overloads are identical to 2020 summer peak. The 230 kV Line 59 is overloaded in 92 of the 120 combinations. Line 6 is the 500 kV transmission line to have the most overloads in all of the 120 combinations. Fall off-peak differs from both summer and spring. Line 48 is a 230 kV transmission line that overloads the most frequently in the fall off-peak N-0 cases. Following that, Line 5, is the first 500 kV overloaded transmission line for fall. As mentioned above the overloads on Lines 48 and 59 will not be used to determine the upgrade needed for interconnecting new renewables because its loading is more load serving related. Also, note that the number of overloads increases for Line 47 with some of the transmission options. This will need to be considered if the transmission option is selected for further consideration.

N-0 Reliability

A transmission element reliability index is normally determined by the Aggregated Megawatt Contingency Overload (AMWCO). This index is used in the following section when discussing reliability under N-1 conditions. The AMWCO calculation does not work for the N-0 or normal condition since no contingency outage occurs. To determine a reliability index for steady state conditions using a similar methodology, a new reliability index is created called the Aggregated Megawatt of Single Overloads (AMWSO). The AMWSO is calculated as follows,

$$AMWSO = \sum ((Overload \% - 100\%) \times (Limit A MVA Rating)) \times 100$$

Considering Scenario 1, Option A, as an example, Table 32 shows how the AMWSO of 121.2 is reached as a sum of the % line overloads multiplied by the A limit Rating.

Table 32: Example Calculation of the AMWSO for Scenario 1, Option A

Line #	Lim A MVA	% of Limit Used	Overload %	Overload % * Limit A
6	1558.8	102.6%	2.6%	40.5%
49	250	112.9%	12.9%	32.3%
58	658	101.3%	1.3%	8.6%
59	295.6	113.5%	3.5%	39.9%
			AMWSO=	121.2

Source: RIR

The AMWSO table for the 2020 Summer Peak is below in Table 33. The “Delta AMWSO” is the difference between a transmission option and transmission Option A. Using the results in Table 33 for example, the delta AMWSO for Scenario 1, Option A is zero ($121.2 - 121.2 = 0$), whereas the delta AMWSO for Scenario 1, Option B is 5.5 ($126.7 - 121.2 = 5.5$). As with the N-1 AMWCO values, negative values indicate that the system becomes less congested and positive values indicate the system is becoming more congested with transmission overloads. For each respective scenario, Option A is treated as the reference case to which all of the other transmission options in the same scenario are compared. This reliability methodology was to account for the different scenario generation profiles otherwise the transmission options cannot be compared to one another.

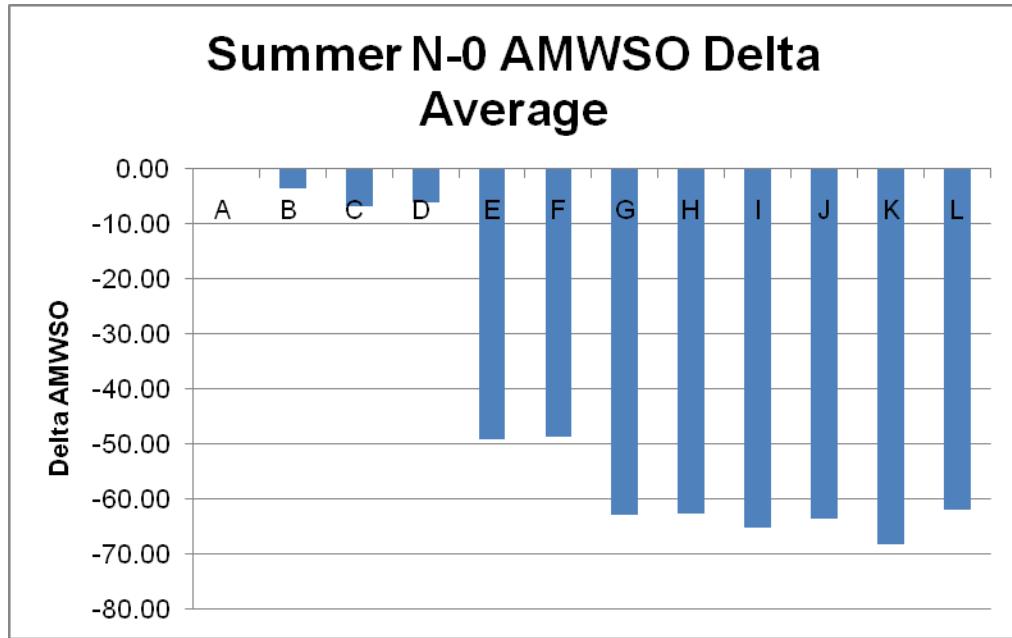
Table 33: AWMSO for 2020 Summer Peak for All Scenarios and Options

Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 1 AMWSO	81	75	68	68	84	85	72	73	63	77	75	76
SCN 1 Delta AMWSO	0	-5	-13	-13	4	5	-9	-8	-17	-4	-6	-5
SCN 2 AMWSO	210	212	211	211	101	101	84	84	80	90	85	90
SCN 2 Delta AMWSO	0	2	1	1	-109	-109	-126	-126	-130	-120	-125	-120
SCN 3 AMWSO	107	71	69	68	169	169	102	103	64	113	109	113
SCN 3 Delta AMWSO	0	-35	-38	-39	62	63	-4	-4	-42	6	2	6
SCN 4 AMWSO	224	224	220	218	212	215	207	207	202	208	201	208
SCN 4 Delta AMWSO	0	0	-4	-6	-12	-9	-17	-17	-22	-16	-23	-16
SCN 5 AMWSO	82	82	78	78	80	80	67	67	147	74	70	74
SCN 5 Delta AMWSO	0	0	-4	-4	-2	-2	-15	-15	65	-8	-12	-8
SCN 6 AMWSO	107	107	104	104	115	115	102	102	66	115	110	115
SCN 6 Delta AMWSO	0	0	-3	-3	8	9	-4	-4	-41	8	4	8
SCN 7 AMWSO	60	60	57	56	68	68	53	53	51	61	59	62
SCN 7 Delta AMWSO	0	0	-4	-4	7	7	-8	-8	-10	1	-2	2
SCN 8 AMWSO	540	544	543	553	127	127	108	109	102	88	78	105
SCN 8 Delta AMWSO	0	4	3	13	-413	-413	-432	-431	-438	-451	-462	-435
SCN 9 AMWSO	71	71	68	67	81	81	65	65	66	73	69	73
SCN 9 Delta AMWSO	0	0	-3	-3	10	10	-6	-6	-5	3	-2	2
SCN 10 AMWSO	132	132	129	128	85	85	124	123	121	79	76	79
SCN 10 Delta AMWSO	0	0	-3	-4	-47	-47	-8	-9	-11	-53	-56	-53
COLUMN DELTA AMWSO AVERAGES	0	-4	-7	-6	-49	-49	-63	-63	-65	-64	-68	-62

Source: RIR

The last row in Table 33 is the column averages of each of the Delta AMWSO transmission options. By averaging transmission options, the impact of each transmission option affects different scenario generation profiles is observed. It can then be determined which transmission option(s) are the most beneficial, regardless of where the generation will be located in California. Figure 24 shows the AMWSO delta averages for summer. Transmission Options E, F, H, J, and K are upgrades north of Tesla and show the most benefit as opposed to south of Tesla transmission Options B through D. Options E, G, and L involves upgrade both north and south of Tesla. Option I is the only one that builds a parallel line over the entire length of Northern California.

Figure 24: Summer N-0 AMWSO Delta Average



Source: RIR

Similarly, The AMWSO table for the 2020 Spring Peak is below in Table 34:

Table 34: AWMSO for 2020 Spring Peak for All Scenarios and Options

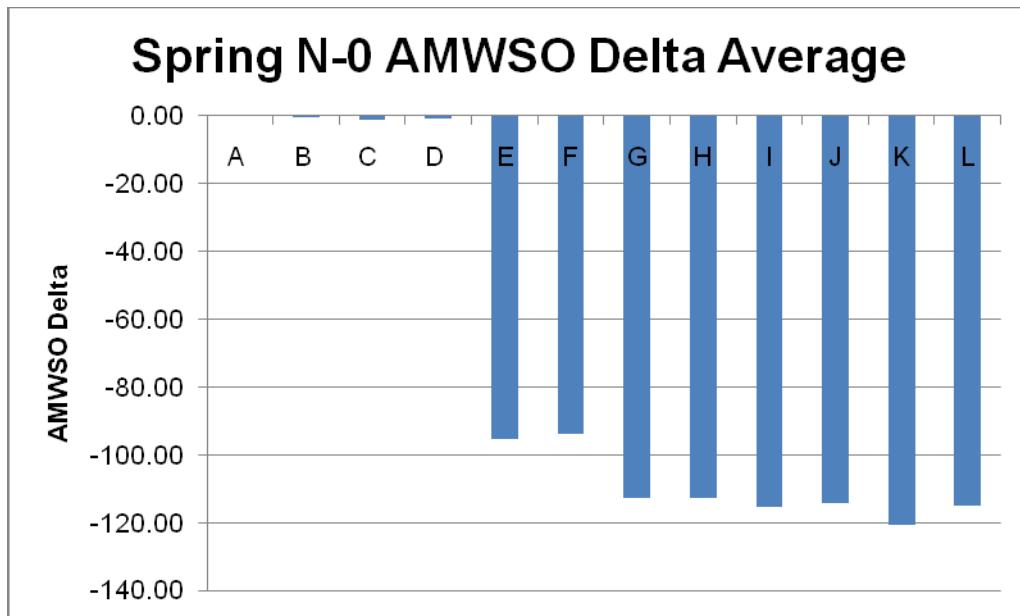
Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 1 AMWSO	20	20	17	17	29	29	14	14	11	21	16	21
SCN 1 Delta AMWSO	0	0	-3	-3	9	9	-6	-6	-9	1	-4	1
SCN 2 AMWSO	71	71	83	85	38	38	20	17	17	30	22	30
SCN 2 Delta AMWSO	0	0	12	13	-33	-33	-51	-55	-55	-42	-50	-42
SCN 3 AMWSO	10	10	7	7	21	21	5	5	2	15	7	15
SCN 3 Delta AMWSO	0	0	-3	-4	10	10	-5	-6	-8	4	-3	4
SCN 4 AMWSO	281	282	278	277	263	274	261	261	257	259	247	254
SCN 4 Delta AMWSO	0	1	-3	-4	-18	-7	-20	-20	-24	-23	-34	-27
SCN 5 AMWSO	15	14	11	11	25	25	8	8	5	16	10	16
SCN 5 Delta AMWSO	0	0	-3	-4	10	10	-7	-7	-10	2	-5	2
SCN 6 AMWSO	20	20	17	17	30	30	14	14	11	22	15	22
SCN 6 Delta AMWSO	0	0	-3	-4	10	10	-6	-6	-10	2	-5	2
SCN 7 AMWSO	0	0	0	0	0	0	0	0	0	0	0	0
SCN 7 Delta AMWSO	0	0	0	0	0	0	0	0	0	0	0	0
SCN 8 AMWSO	811	810	807	810	42	43	13	13	11	11	0	9

Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 8 Delta AMWSO	0	-1	-4	-1	-769	-768	-798	-798	-800	-800	-811	-802
SCN 9 AMWSO	224	224	225	223	111	113	0	0	0	3	0	3
SCN 9 Delta AMWSO	0	0	1	-1	-114	-112	-224	-224	-224	-222	-224	-222
SCN 10 AMWSO	106	106	102	102	48	48	94	98	91	39	33	39
SCN 10 Delta AMWSO	0	0	-3	-4	-58	-58	-12	-8	-15	-67	-73	-67
COLUMN DELTA AMWSO AVERAGES	0	0	-1	-1	-95	-94	-113	-113	-115	-114	-121	-115

Source: RIR

Figure 25 is the AMWSO delta averages for spring. The results are very similar to those from summer. Again, transmission options north of Tesla and both north and south of Tesla (E through L) are very beneficial, and transmission options south of Tesla (B through D) show little benefit. In Scenario 7, line 6, Malin to Round Mt. 500 kV was the only transmission line above 115 kV to overload and was excluded in the AMWSO calculations.

Figure 25: Spring N-0 AMWSO Delta Average



Source: RIR

Similarly, the AMWSO table for the 2020 Fall Off-Peak is below in Table 35:

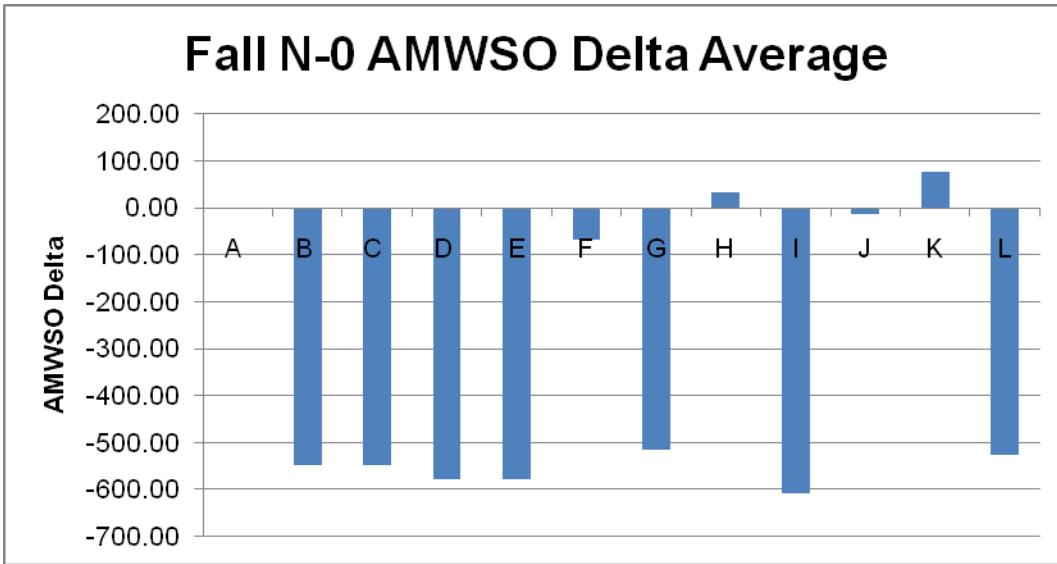
Table 35: AWMSO for 2020 Fall Off-Peak for All Scenarios and Options

Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 1 AMWSO	2394	1445	1443	1431	1341	2284	1500	2513	460	2425	2530	1496
SCN 1 Delta AMWSO	0	-949	-950	-963	-1053	-109	-894	120	-1934	32	136	-897
SCN 2 AMWSO	411	63	66	66	75	394	38	379	38	372	437	52
SCN 2 Delta AMWSO	0	-348	-345	-345	-336	-17	-373	-32	-373	-39	27	-358
SCN 3 AMWSO	314	1	3	8	0	291	40	349	38	332	380	40
SCN 3 Delta AMWSO	0	-314	-311	-306	-314	-24	-274	35	-277	18	66	-274
SCN 4 AMWSO	556	279	282	281	239	462	285	570	290	550	620	296
SCN 4 Delta AMWSO	0	-277	-274	-275	-318	-94	-271	14	-266	-6	64	-260
SCN 5 AMWSO	810	244	229	230	218	748	279	855	277	817	916	266
SCN 5 Delta AMWSO	0	-566	-581	-580	-592	-62	-531	45	-533	7	106	-544
SCN 6 AMWSO	570	122	127	129	83	480	182	606	172	564	664	146
SCN 6 Delta AMWSO	0	-448	-443	-441	-487	-90	-388	36	-398	-6	93	-424
SCN 7 AMWSO	3298	2083	2085	2073	1977	3180	2189	3424	2243	3288	3498	2129
SCN 7 Delta AMWSO	0	-1215	-1214	-1225	-1321	-118	-1109	126	-1055	-11	199	-1169
SCN 8 AMWSO	299	9	12	12	9	258	9	310	85	294	330	70
SCN 8 Delta AMWSO	0	-290	-287	-287	-290	-41	-290	11	-214	-5	32	-229
SCN 9 AMWSO	1172	451	433	145	454	1100	400	1087	407	1022	1122	368
SCN 9 Delta AMWSO	0	-721	-739	-1027	-718	-72	-773	-85	-765	-150	-51	-804
SCN 10 AMWSO	366	22	25	26	5	325	108	414	108	387	446	72
SCN 10 Delta AMWSO	0	-344	-341	-340	-361	-41	-258	48	-258	21	80	-294
COLUMN DELTA AMWSO AVERAGES	0	-547	-548	-579	-579	-67	-516	32	-607	-14	75	-525

Source: RIR

Figure 26 below is the AMWSO delta averages for fall. Since fall is an off-peak season, the power flows from south to north. The fall results are very different from summer and spring. The transmission options containing upgrades south of Tesla show a huge amount of benefit to the system. Transmission Options F, H, J, and K contain no upgrades south of Tesla and show either very little benefit or show a positive impact onto the system. Transmission Options G, I, and L have C3ET transmission additions that are south of Tesla, hence showing benefit to the system.

Figure 26: Fall N-0 AMWSO Delta Average



Source: RIR

N-1 Results

The second part of the analysis is the N-1 contingency cases. The method described previously for the N-0 case for obtaining the maximum number for each option is repeated where the results from each scenario and transmission option is aggregated into a list and sorted by greatest number of occurrences. The maximum number of occurrences that a specific line can be overloaded through each combination of transmission option and resource scenario is 120. The top 10 transmission line overloads under N-1 conditions is ranked from worst overloaded line to fewest number of overloads, i.e. the most number of instances of overload through all the scenarios and options, to the least number of instances of overloads through all the scenarios and options. When a zero is marked (highlighted in green) in the table, it indicates that the line has not overloaded in any of the scenarios. Cells are highlighted in yellow if the line number of overloads compared to Option A (no additional transmission) decreases by more than two when all renewable resource scenarios are considered. For example, in Table 36, Line 29 under Option A has 6 overloads when all resource scenarios are considered. The number of overloads decreased to two and three with Options G, H, I, J, K, or L across all resource scenarios. The corresponding cells are highlighted in yellow. These green and yellow highlights identify the transmission options, which could help decrease the number of overloads for that line for all resource scenarios considered.

In Table 36, below, the top 10 line overloads are shown for summer under N-1 contingencies. Line 30, 33, and 48 are 230 kV transmission lines that overload in all of the scenarios for any transmission option. Line 6 is the first 500 kV line with significant number of overloads, 110 out of 120. Aside

from line 2, the rest of the lines are 230 kV overloads for the top 10 N-1 contingencies under summer peak conditions.

Table 36: Top 10 N-1 Overloads for 2020 Summer Peak

Line #	Overload Range %	A	B	C	D	E	F	G	H	I	J	K	L	Total
Line 30	107-109	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 33	107-109	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 48	107-115	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 6	110-127	10	10	10	10	10	10	10	10	10	10	0	10	110
Line 29	101-132	6	6	6	6	6	6	2	2	2	2	2	3	49
Line 20	100-115	6	6	6	6	6	6	1	1	2	2	3	3	48
Line 23	100-117	6	6	6	6	6	6	1	1	2	2	3	3	48
Line 2	101-118	10	10	10	10	0	0	0	0	0	0	0	0	40
Line 10	100-118	7	7	7	7	2	2	1	1	2	0	0	1	37
Line 18	103-153	2	2	2	2	2	2	2	2	2	2	2	2	24

Source: RIR

Table 37 below lists the top 10 N-1 line overloads for spring peak cases. Unlike the summer results, the transmission line to overload most frequently is line 6, a 500 kV transmission line that overloads in 110 out of 120 possibilities. Line 2 is a 500 kV line that has the third most number of overloads. The rest of the lines identified are 230 kV lines that overload most frequently in the spring peak N-1 cases. As mentioned above the overload on Lines 30, 33, and 48 will not be used to determine the upgrade needed for interconnecting new renewables because its loading is more load-serving related.

Table 37: Top 10 N-1 Overloads for 2020 Spring Peak

Line #	Overload Range %	A	B	C	D	E	F	G	H	I	J	K	L	Total
Line 6	101-120	10	10	10	10	10	10	10	10	10	10	0	10	110
Line 7	103-144	9	9	9	9	4	5	1	0	0	0	0	0	46
Line 2	101-119	9	9	9	9	1	2	2	1	1	1	0	1	45
Line 45	102-153	9	9	9	9	3	4	1	0	0	0	0	0	44
Line 18	108-176	3	3	3	3	3	3	3	3	3	3	3	3	36
Line 19	108-174	3	3	3	3	3	3	3	3	3	3	3	3	36
Line 17	100-144	2	2	2	2	2	2	2	2	2	2	2	2	24
Line 52	101-118	5	5	5	5	2	2	0	0	0	0	0	0	24
Line 8	109-193	3	3	3	3	2	2	1	1	1	1	1	1	22
Line 9	109-195	3	3	3	3	2	2	1	1	1	1	1	1	22

Source: RIR

Table 38 below shows the results for fall off-peak season under N-1 contingency ratings. As with the N-0 results, the fall N-1 results are significantly different than the summer and spring N-1 results. Notably, all of the line overloads are 230 kV lines with no 500 kV lines making fall's top 10 list. Lines 44, 48, 50, and 53 are 230 kV lines that overload 100% of the time regardless of the scenario or transmission option upgrade added onto the system.

Table 38: Top 10 N-1 Overloads for 2020 Fall Off-Peak

Line #	Overload Range %	A	B	C	D	E	F	G	H	I	J	K	L	Total
Line 44	133-142	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 48	103-135	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 50	116-124	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 53	118-124	10	10	10	10	10	10	10	10	10	10	10	10	120
Line 51	100-137	10	10	10	10	7	7	10	10	10	9	6	9	108
Line 39	100-144	10	2	2	2	2	10	2	10	1	10	10	2	63
Line 26	123-137	10	0	0	0	0	10	0	10	0	10	10	0	50
Line 31	119-137	10	0	0	0	0	10	0	10	0	10	10	0	50
Line 32	112-129	10	0	0	0	0	10	0	10	0	10	10	0	50
Line 34	111-140	10	0	0	0	0	10	0	10	0	10	10	0	50

Source: RIR

N-1 Reliability

While the particular overloaded lines indicate where the problems are occurring, the reliability index provides a broader picture of the effect of the upgrades on the grid. The security of the electrical system is determined by the ability of the system to withstand equipment failures. The standard approach of simulating line outages under N-1 emergency ratings has been used to determine the system reliability under emergency conditions. Weak elements that present overloads under emergency N-1 ratings will be identified, and a ranking method will be used to prioritize the heavily loaded transmission elements.

The AMWCO (Aggregated Megawatt Contingency Overload) will be used to assign a reliability index to each scenario/transmission combination so comparisons can be made between different combinations. The equation below is used to calculate the AMWCO. The sum of the each element overloaded over 100% is multiplied by the Limit B MVA rating of the transmission line that is in question. This value, Aggregated Percentage Contingency Overload (APCO) is multiplied by 100 and summed one final time to achieve the AMWCO value.

$$AMWCO = \sum_{APCO} ((\sum(Overload \% - 100\%) \times (Limit B MVA Rating)) \times 100)$$

More information on AMWCO can be found in the Energy Commission's report *Strategic Value Analysis for Integrating Renewable Technologies in Meeting Renewable Penetration Targets*, June 2005, CEC-500-2005-106.

The AMWCO table for the 2020 Summer Peak is below in Table 39. The "Delta AMWCO" is the difference between a transmission option and transmission Option A similarly from the N-0 section as previously discussed. Negative values indicate that the system becomes more reliable, and positive values indicate the system is becoming less reliable with transmission overloads. For each respective scenario, Option A is treated as the reference case to which all of the other transmission options in the same scenario are compared. This reliability methodology was to account for the different scenario generation profiles otherwise the transmission options cannot be compared to one another.

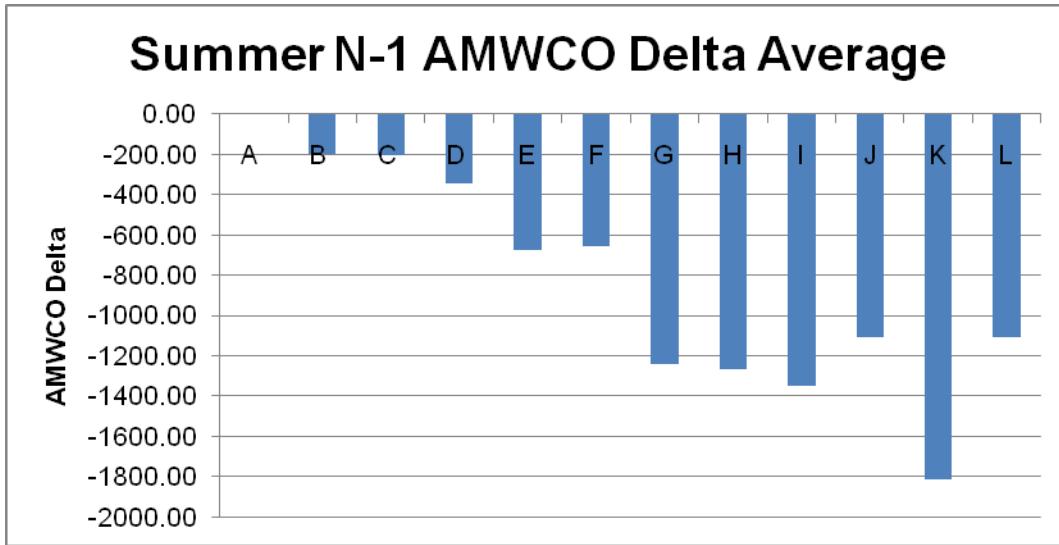
Table 39: N-1 AMWCO Results for 2020 Summer Peak

Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 1 AMWCO	3026	3024	3000	3006	2606	2607	1646	1595	1699	2061	1108	2124
SCN 1 Delta AMWCO	0	-2	-25	-20	-419	-419	-1380	-1430	-1326	-964	-1917	-902
SCN 2 AMWCO	3140	3157	3149	3132	2573	2572	1424	1396	1527	1642	1090	1655
SCN 2 Delta AMWCO	0	17	9	-9	-567	-568	-1716	-1744	-1614	-1498	-2051	-1486
SCN 3 AMWCO	2753	2594	2571	2571	2526	2542	1863	1572	1583	1627	1215	1638
SCN 3 Delta AMWCO	0	-159	-182	-181	-227	-211	-889	-1180	-1169	-1126	-1537	-1115
SCN 4 AMWCO	2713	2351	2338	2330	2046	2055	1633	1809	1642	2259	1497	1884
SCN 4 Delta AMWCO	0	-362	-375	-383	-667	-658	-1080	-904	-1071	-454	-1216	-829
SCN 5 AMWCO	2803	2808	2799	1765	2261	2277	1744	1731	1789	1873	1083	1882
SCN 5 Delta AMWCO	0	5	-4	-1038	-542	-526	-1059	-1072	-1014	-930	-1719	-921
SCN 6 AMWCO	2639	2636	2627	2629	2251	2250	1754	1751	1454	1724	1134	1734
SCN 6 Delta AMWCO	0	-3	-11	-9	-387	-389	-885	-888	-1185	-915	-1505	-904
SCN 7 AMWCO	2992	3027	2980	2915	2223	2347	1767	1749	1618	1805	909	1815
SCN 7 Delta AMWCO	0	34	-12	-77	-769	-646	-1226	-1243	-1375	-1187	-2084	-1178
SCN 8 AMWCO	4168	3115	3111	3133	1668	1803	1610	1602	1492	1654	1066	1506
SCN 8 Delta AMWCO	0	-1053	-1057	-1035	-2500	-2365	-2558	-2566	-2677	-2514	-3102	-2662
SCN 9 AMWCO	2630	2636	2590	2235	2121	2341	1654	1642	1384	1733	937	1750
SCN 9 Delta AMWCO	0	6	-41	-396	-509	-290	-977	-989	-1246	-898	-1693	-881
SCN 10 AMWCO	2331	1872	2009	2018	2158	1808	1680	1653	1529	1753	1043	2158
SCN 10 Delta AMWCO	0	-459	-322	-314	-173	-524	-651	-678	-803	-579	-1288	-173
COLUMN DELTA AMWCO AVERAGES	0	-198	-202	-346	-676	-659	-1242	-1269	-1348	-1106	-1811	-1105

Source: RIR

As calculated in the N-0 section, transmission options (A through L) are averaged across all scenarios to determine which transmission options provided the greatest benefit regardless of the generator location. Figure 27 below graphically displays the magnitude of the transmission option AMWCO delta averages. Under N-1 conditions, the transmission options have a greater impact in system benefit as compared to N-0 conditions before taking into account the probability of occurrence of an N-1 contingency. All of the transmission options show a level of benefit to the system. Option B has the least average benefit, and Option K has the largest average benefit. Transmission upgrades north of Tesla had the greatest overall benefit when compared to the transmission upgrades south of Tesla (Option B through Option D).

Figure 27: Summer N-1 AMWCO Delta Average



Source: RIR

Similarly, the AMWCO table for the 2020 Spring Peak is below in Table 40:

Table 40: AWMCO for 2020 Spring Peak for All Scenarios and Options

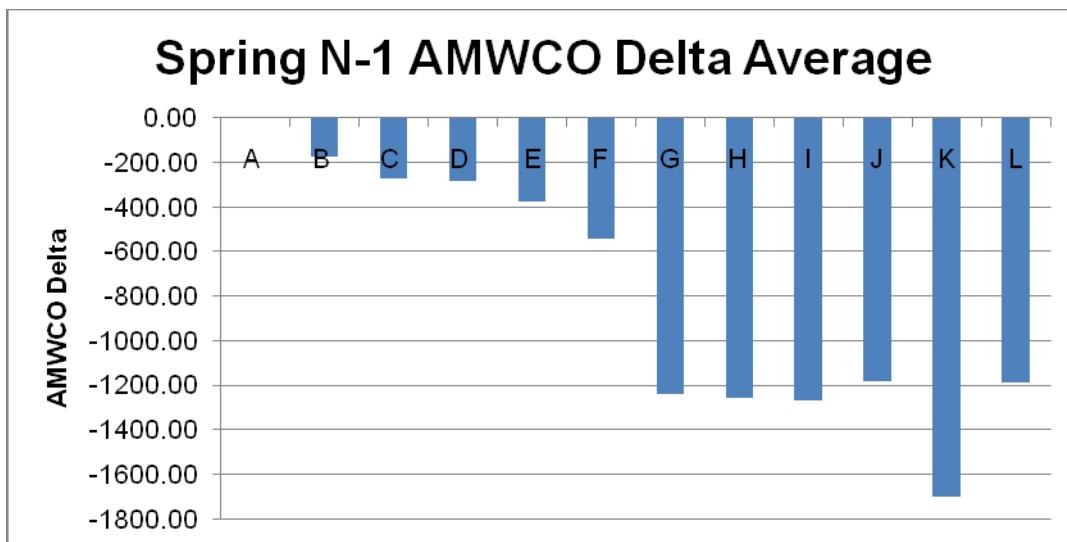
Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 1 AMWSO	2391	2198	2190	2190	2301	1914	1919	1630	1626	1814	929	1822
SCN 1 Delta AMWSO	0	-193	-201	-201	-90	-477	-472	-761	-766	-577	-1462	-569
SCN 2 AMWSO	2392	2387	2381	2375	2331	1943	1036	1285	1037	1117	801	1131
SCN 2 Delta AMWSO	0	-5	-10	-17	-61	-449	-1355	-1106	-1355	-1274	-1591	-1260
SCN 3 AMWSO	2046	2092	2097	2115	1587	1271	817	818	817	898	529	916
SCN 3 Delta AMWSO	0	46	51	69	-459	-775	-1229	-1228	-1229	-1148	-1517	-1130
SCN 4 AMWSO	1902	1928	1931	1951	1784	2104	1142	1119	1145	1234	786	1258
SCN 4 Delta AMWSO	0	26	29	49	-118	202	-760	-783	-757	-668	-1115	-644
SCN 5 AMWSO	1834	1476	1476	1495	1734	1717	961	940	959	1057	581	1075
SCN 5 Delta AMWSO	0	-358	-358	-339	-100	-117	-872	-894	-875	-776	-1252	-759
SCN 6 AMWSO	2020	2071	1657	1652	1805	1463	1242	1209	1250	1074	601	1094
SCN 6 Delta AMWSO	0	51	-363	-368	-215	-557	-778	-811	-770	-946	-1419	-926
SCN 7 AMWSO	2526	2526	2494	2343	2525	1978	1369	1343	1363	1541	690	1560
SCN 7 Delta AMWSO	0	0	-33	-183	-2	-548	-1158	-1183	-1163	-986	-1837	-967
SCN 8 AMWSO	4603	3591	3577	3561	2126	2131	982	1199	980	1309	950	1096
SCN 8 Delta AMWSO	0	-1012	-1027	-1043	-2477	-2472	-3621	-3404	-3624	-3294	-3653	-3507
SCN 9 AMWSO	3018	3024	2514	2498	2980	2970	1241	1225	1239	1386	794	1396

Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 9 Delta AMWSO	0	6	-504	-520	-38	-48	-1777	-1794	-1779	-1632	-2225	-1622
SCN 10 AMWSO	1636	1318	1316	1333	1445	1437	1281	999	1284	1118	678	1130
SCN 10 Delta AMWSO	0	-318	-320	-304	-192	-199	-355	-637	-352	-518	-958	-507
COLUMN DELTA AMWSO AVERAGES	0	-176	-274	-286	-375	-544	-1238	-1260	-1267	-1182	-1703	-1189

Source: RIR

Figure 28 is the AMWCO Delta average graph for spring N-1. The spring results are very similar to summer results. On average, all of the transmission options provide overload relief under single contingency outages. Like summer, Option B has the least average benefit, and Option K has the largest average benefit for spring. Transmission options that include a 500 kV line between Round Mt. and Tesla 500 kV (Option G through Option L) provide the largest benefit compared to Option B through Option F.

Figure 28: Spring N-1 AMWCO Delta Average



Source: RIR

Similarly, the AMWCO table for the 2020 Spring Peak is below in Table 41.

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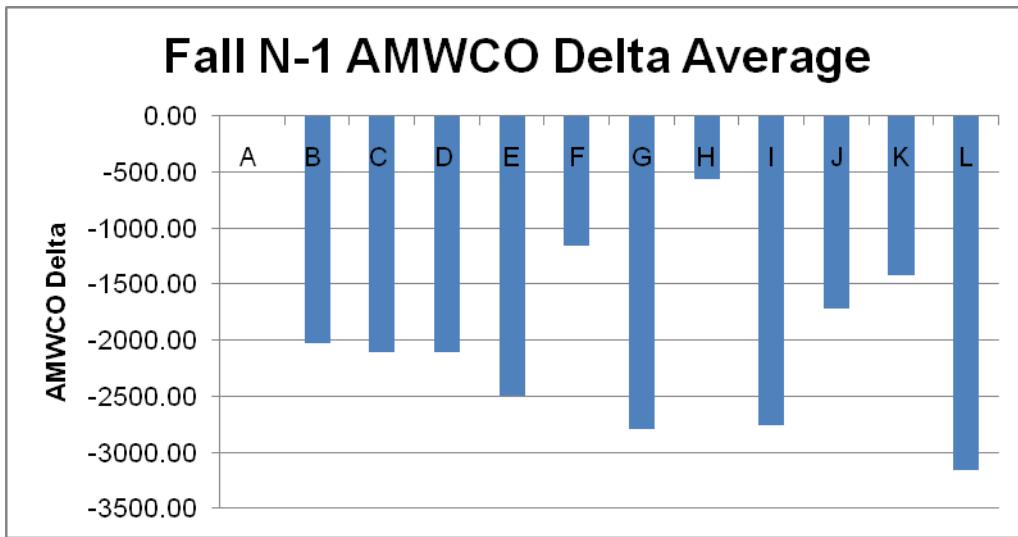
Table 41: AWMCO for 2020 Fall Off Peak for All Scenarios and Options

Scenario	A	B	C	D	E	F	G	H	I	J	K	L
SCN 1 AMWSO	8038	3054	3130	3109	3325	6139	2356	8571	986	6020	6166	2503
SCN 1 Delta AMWSO	0	-4984	-4908	-4929	-4713	-1899	-5682	533	-7052	-2018	-1872	-5535
SCN 2 AMWSO	3064	2280	2295	2286	1858	2389	1256	2079	1278	1401	1249	870
SCN 2 Delta AMWSO	0	-784	-769	-778	-1205	-675	-1808	-985	-1786	-1662	-1814	-2194
SCN 3 AMWSO	2542	2130	2128	2147	1378	1856	1268	1860	1263	1139	1306	711
SCN 3 Delta AMWSO	0	-411	-414	-394	-1163	-686	-1274	-682	-1278	-1403	-1236	-1831
SCN 4 AMWSO	3093	2730	2466	2471	1928	2066	1620	1993	1680	1585	1306	1305
SCN 4 Delta AMWSO	0	-363	-627	-622	-1165	-1027	-1473	-1100	-1413	-1508	-1787	-1788
SCN 5 AMWSO	3172	1382	1266	1262	853	2691	875	2871	881	2210	2312	876
SCN 5 Delta AMWSO	0	-1790	-1906	-1910	-2319	-481	-2297	-301	-2291	-962	-860	-2296
SCN 6 AMWSO	2937	1939	1789	1795	961	1871	1249	2406	1246	1605	2804	931
SCN 6 Delta AMWSO	0	-998	-1148	-1141	-1976	-1066	-1688	-531	-1690	-1332	-132	-2006
SCN 7 AMWSO	12326	5521	5495	5459	4308	8329	5649	13798	5648	8671	10379	3990
SCN 7 Delta AMWSO	0	-6805	-6831	-6867	-8018	-3997	-6677	1472	-6678	-3655	-1947	-8336
SCN 8 AMWSO	2944	2422	2183	2184	1783	2317	1230	1803	1243	1657	1635	975
SCN 8 Delta AMWSO	0	-522	-761	-760	-1161	-627	-1713	-1141	-1701	-1286	-1309	-1968
SCN 9 AMWSO	5934	2961	2952	2951	3231	4872	1190	2890	2762	2803	3197	1017
SCN 9 Delta AMWSO	0	-2974	-2983	-2984	-2703	-1062	-4745	-3044	-3172	-3131	-2738	-4917
SCN 10 AMWSO	1983	1391	1269	1255	1436	1911	1428	2156	1432	1802	1484	1328
SCN 10 Delta AMWSO	0	-592	-714	-728	-547	-73	-556	173	-551	-182	-499	-655
COLUMN DELTA AMWSO AVERAGES	0	-2022	-2106	-2111	-2497	-1159	-2791	-561	-2761	-1714	-1419	-3153

Source: RIR

Figure 29 below is the fall N-1 AMWCO delta average graph. The results here are similar to fall N-0 and different from N-1 summer and spring. Since fall is an off-peak season, the prevailing power flows over the major transmission lines are from south to north. Transmission Options B, C, and D are upgrades south of Tesla and provide a benefit to the system. The transmission options that contain upgrades south of Tesla show a benefit to the system. Transmission Options F, H, J, and K contain no upgrades south of Tesla but still show an improvement to the overload congestion on the system. Transmission Options G, I, and L have C3ET transmission additions that are south of Tesla, which also results in a benefit to the system.

Figure 29: Fall N-1 AMWCO Delta Average



Source: RIR

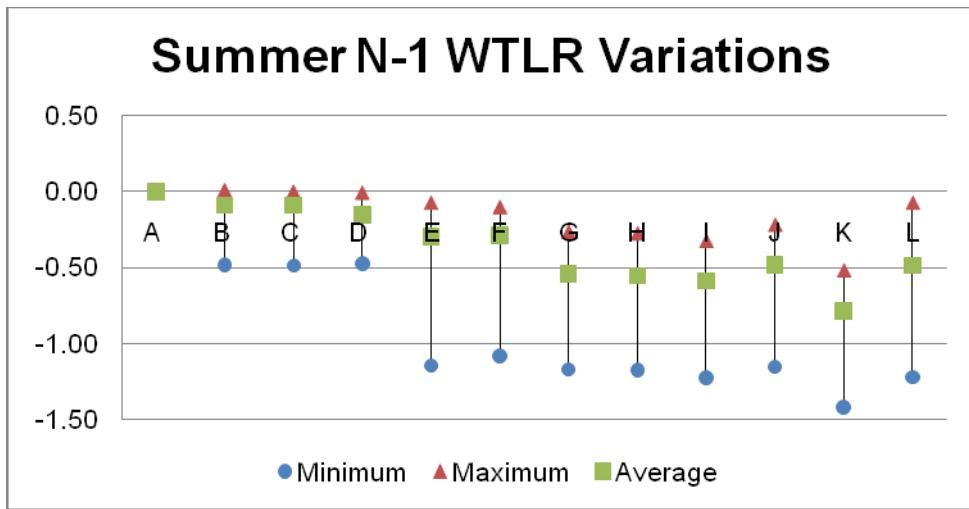
N-1 WTLR

The delta AMWCO is the difference between the AMWCO for the base case and each new renewable case. Delta AMWCO is a transmission reliability index, with a unit of megawatts. A negative delta AMWCO is an indication of improvement in transmission reliability. The larger the negative delta AMWCO, as in the AMWSO example described above, the more beneficial the transmission is to the reliability in that area.

It is difficult to compare delta AMWCOS since the numbers vary considerably by the generation profile of a specific scenario. Therefore, if the AMWCO is divided by the generation addition (MW), the research team can normalize the value to a Weighted Transmission Loading Relief (WTLR) value. For example, using Summer Scenario 8, Option A (without any transmission additions) has 2,180 MW of generation added (after capacity factors are accounted for), resulting in a base AMWCO value of 4,168. Summer Scenario 8 Option E (addition of CNC and C3ET transmission upgrades) with the same 2,180 MW of generation resulted in an AMWCO value of 1,668. The delta AMWCO is -2,500, which means that Option E transmission upgrades relieved the system of cumulative -2,500 MW worth of potential overload. Dividing the AMWCO delta, -2,500 MW, by the generation addition amount, 2,180 MW, results in a WTLR value of -1.15. A WTLR of -1.15 means that with the transmission upgrade of CNC and C3ET, the upgrade will likely reduce 1.15 MW of overload in transmission elements per MW of generation addition during contingencies, showing that the addition of certain upgrades can decrease more overloads than the generation addition, upon system redispatch under an N-1 contingency.

The graphs below are in Figure 30, Figure 31, and Figure 32, show the minimum, maximum and average WTLR value for all of the transmission options for summer, spring, and fall system conditions. For all three graphs, the lowest WTLR value in all of the transmission options will provide the most benefit to the electrical grid. The largest WTLR value in each of the transmission options provides the least benefits to the grid; a positive WTLR indicates a detrimental effect on grid reliability. The green squares are the column averages of each respective transmission option in each season. This can provide a trend for each of the transmission options in each season.

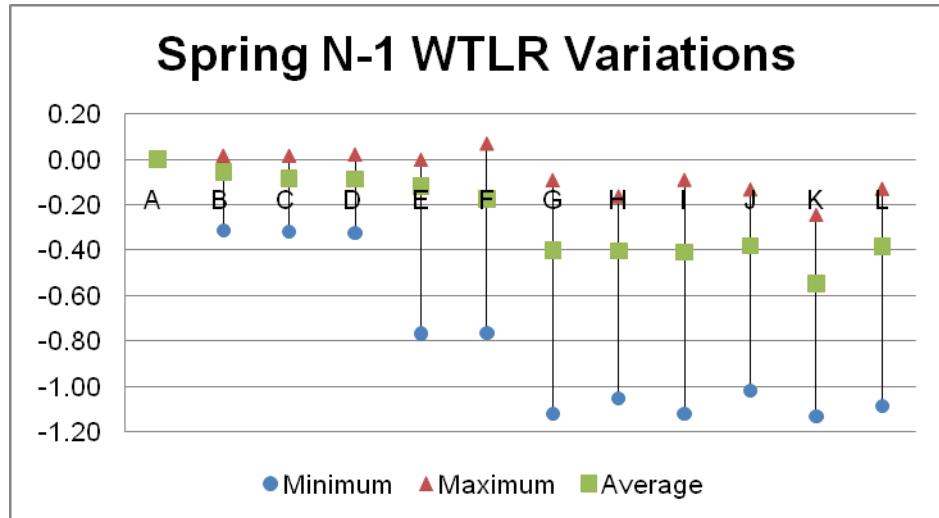
Figure 30: Summer N-1 WTLR Variations



Source: RIR

The results for the WTLR draw the same conclusions as the delta AMWCO. In Figure 30, on average, all of the transmission option WTLR averages are in the negative range. However, since these are only averages, there are generation profiles that may increase congestion when paired with a specific transmission option. In Figure 30 and Figure 31, the results are very close to identical. As a reminder, both summer and spring are peak cases with prevailing electrical power flows from north to south. Therefore, many of the transmission options with a majority of upgrades in the northern part of California experience larger benefit increase in reliability, hence the lower WLTR averages for transmission Options E through K. Transmission Options B, C, and D, although show a minor benefit, is not as beneficial since these transmission upgrades are located in areas south of Tesla.

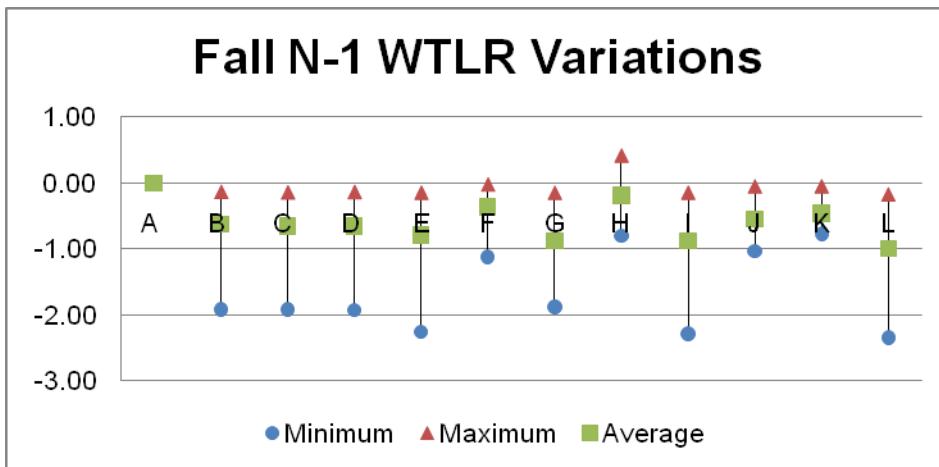
Figure 31: Spring N-1 WTLR Variations



Source: RIR

The fall WTLR variations in Figure 32 below differ from spring and summer since it is an off-peak case with prevailing electrical power flows over the major transmission lines from south to north. All of the transmission Options B through L are in the negative range as well. However, the options with the most transmission upgrades in area south of Tesla provide the best minimum WTLR value, which lower the average WTLR value as well. Transmission Options B, C, D, E, G, I, and L all have the lowest WTLR values (i.e., increases reliability) and also contain transmission upgrades in areas south of Tesla.

Figure 32: Fall N-1 WTLR Variations



Source: RIR

Additional Transmission Problems for N-1

Although the result highlights the most beneficial transmission options of implementing the generation and the upgrade with the most beneficial impact, certain base case overloads must be considered. These overloads exist before any additional generation is added, and adding additional generation only increases the problem. It is likely that these lines will be upgraded/fixed before generation is installed but are not considered major upgrades in this analysis.

Table 42 below show commonly overloaded lines that appear in many of the N-1 contingency results and often influence the delta AMWCO value. When one of the transmission lines listed below become overloaded in every outage, it skews the AMWCO value. The solution is to omit the APCO (Aggregated Percentage Contingency Overload) value from being included in the final AMWCO value. Therefore, these lines should be considered for further analysis when installing new renewable generation in California.

Table 42: Additional 230 kV Transmission Problems

Line	From Substation	To Substation	Nominal Voltage
Line 8	COTWD_F	BRNY_FST	230
Line 9	BRNY_FST	PIT 1	230
Line 11	PIT 3	ROUND MT	230
Line 13	POE	RIO OSO	230
Line 18	T22_93	FULTON	230
Line 19	LAKEVILLE	T22_93	230
Line 27	PANOCHÉ	GATES	230
Line 48	FOLSOM	ORANGEVL	230

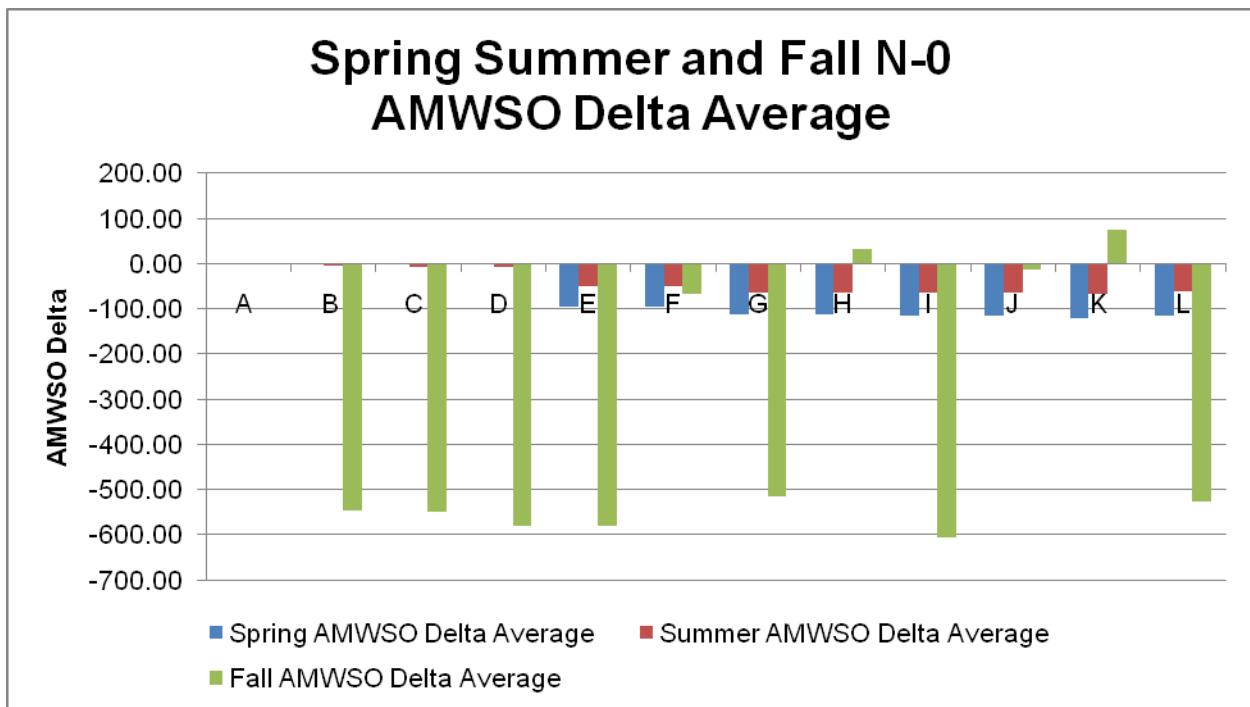
Source: RIR

Conclusion

Figure 33 and Figure 34 below summarize the power flow analyses described in this chapter for steady state normal (N-0) and first contingency (N-1) conditions. As mentioned, 120 simulations were modeled for each season, and results indicate that depending on where the renewable generation is located, certain transmission options (upgrades) will provide different levels of reliability benefits. For the N-0, Option H and K for the fall are the only 2 transmission options that when their level of benefit (AMWSO) was averaged across all 10 scenarios, still results in additional potential overloads. Spring and summer under N-0 conditions, on average, benefitted from the additional support with transmission upgrades.

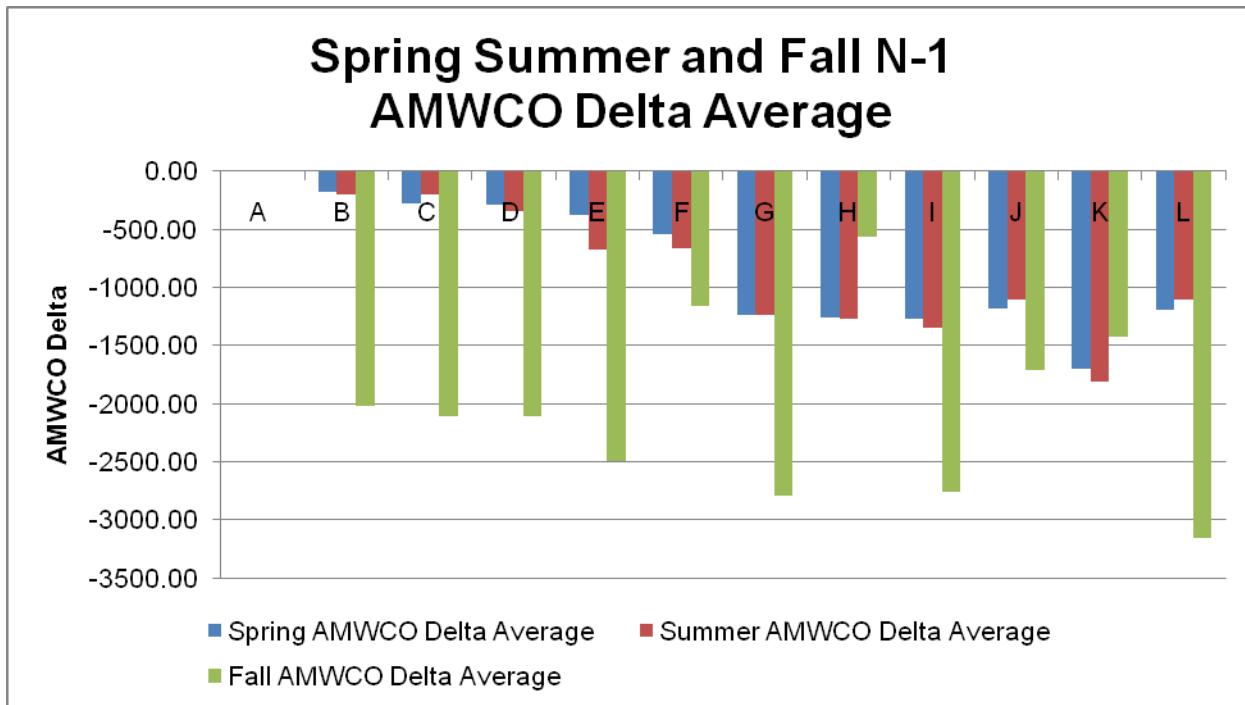
For the N-1 AMWCO delta averages, all of the transmission options provided a benefit on average compared to Option A (no upgrades) regardless of where the renewable generation is located. For summer and spring, the largest congestion relief came with transmission upgrades north of Tesla (Options E through L). For fall, the largest congestion relief came with transmission upgrades south of Tesla (Options B, C, D, E, G, I, and L).

Figure 33: Spring, Summer, and Fall N-0 AMWSO Delta Average



Source: RIR

Figure 34: Spring, Summer, and Fall N-1 AMWCO Delta Average



Source: RIR

CHAPTER 8:

Transmission Ranking

This chapter explores three different methods of ranking the transmission options and the transmission projects associated with the options based on the potential problems identified. From this information, the research team can then develop the transmission projects that can be considered “least regret” when taking into account the 10 resource scenarios (Table 25) considered and the system conditions under the load level and the seasons studied.

A list of top 10 N-0 and N-1 overloads from Option A is listed below in Table 43 and Source: RIR

Table 44. Both of these tables list the problematic lines that occur when only renewable generation is added to the system without additional transmission support (Transmission Option A). This will set a foundation to determine the problematic lines before and after transmission options. Both tables are ranked by the maximum number of occurrences that a line overloads under Option A for spring, summer, and fall. When ranking numbers are identical, the lines overloaded the same amount. For example, in Source: RIR

Table 44, the last six top overloads are ranked fourth due to all of those lines overloading the same number of times for all scenarios under spring, summer, and fall for emergency ratings. The overloads have been separated because N-0 overloads have much higher impacts than N-1.

Table 43: Top 10 N-0 Overloads for Option A

Ranking	Line #	From Substation	To Substation	Nominal Voltage
1	Line 59	C.COSTA	LONETREE	230
2	Line 5	GATES	MIDWAY	500
3	Line 48	FOLSOM	ORANGEVL	230
4	Line 6	MALIN	ROUND MT	500
5	Line 1	TABLE MT	VACA DIXON	500
5	Line 26	PANOCHE	MCMULLN1	230
6	Line 18	T22_93	FULTON	230
6	Line 19	LAKEVILLE	T22_93	230
7	Line 4	LOS BANOS	LOSGAT11	500
7	Line 13	POE	RIO OSO	230

Source: RIR

Table 44: Top 10 N-1 Overloads for Option A

Ranking	Line #	From Substation	To Substation	Nominal Voltage
1	Line 48	FOLSOM	ORANGEVL	230
1	Line 6	MALIN	ROUND MT	500
2	Line 2	ROUND MT	TABLE MT	500
3	Line 52	OLINDAW	COTWDWAP	230
4	Line 26	PANOCHE	MCMULLN1	230
4	Line 30	GREGG	FGRDN T2	230
4	Line 31	MCMULLN1	KEARNEY	230
4	Line 32	BULRD_EC	KEARNEY	230
4	Line 33	HERNDON	FGRDN T1	230
4	Line 34	MC CALL	HENTAP2	230

Source: RIR

Transmission Ranking Method 1

To rank the transmission options that would be most beneficial, we will first review the number potential of transmission problems if no transmission additions (Option A) were made. A simplistic way is to combine the number potential overloads for Option A in Tables 28, 29, and 30 and resort them based on the number of overloads and then on the percentage loading. Leaving out Lines 48 and 59, which are primarily load-serving-related, and summarizing the results in Table 45, the authors found for N-0:

Table 45: Combined Incident of Potential Overloads for N-0

Line #	From Substation	To Substation	Nominal Voltage	% loading Range	# of overloads	Options to mitigate Overloads	
						Complete	Partial
Line 5	GATES	MIDWAY	500	101-142	10		B, C, D, E, G, I, L
Line 6	MALIN	ROUND MT.	500	100-112	8	K	
Line 4	LOS BANOS	GATES	500	100-132	2		I
Line 1	TABLE MT.	VACA DIXON	500	104-113	1	E, F, K	G, H, I
Line 26	PANOACHE	MCMULLN1	230	100-105	5	B, C, D, E, G, I, L	
Line 10	CPVSTA	CORTINA	230	100-110	4	J, K	E, F, L
Line 18	T22_93	FULTON	230	119-122	2	--	
Line 19	LAKEVILLE	T22_93	230	118-120	2	--	
Line 13	POE	RIO OSO	230	117-118	2	E, F, J, K, L	
Line 68	ELKGROVE	RNCHSECO	230	109-109	2	--	
Line 40	TEMPLETN	MORROBAY	230	108-116	2	--	
Line 27	PANOACHE	GATES	230	103-118	2		B, C, D, E, G, I, L
Line 14	RIO OSO	ATLANTC	230	102-107	2		K
Line 18	T22_93	FULTON	230	136-140	1	--	
Line 19	LAKEVILLE	T22_93	230	136-139	1	--	
Line 11	PIT 3	ROUND MT	230	128-133	1	G, H, I, J, K, L	
Line 47	FOLSOM	LAKE	230	100-118	0	--	

Source: RIR

Mapping the lines that can potentially overload to the instances that the Transmission options can either completely or partially mitigate the overloads, the research team can identify the transmission projects that are common to the most effective transmission options. These are shown (highlighted in green) in Table 46.

Table 46: Transmission Upgrade Breakdown for N-0

Facility Operating Voltage	Transmission Options										
	B	C	D	E	F	G	H	I	J	K	L
Number of 500 kV overloads reduced	1	1	1	2	1	2	1	3	0	2	1
Number of 230 kV overloads reduced	2	2	2	4	2	3	1	3	3	4	5
Total number of overloads reduced	3	3	3	6	3	5	2	6	3	6	6
Transmission Additions											
C3ET Project	X	X	X	X		X		X			X
Gregg-Cottle			X					X			
Cottle-Tesla/Tracy		X	X					X			
Round Mt – Tesla/Tracy						X	X	X	X	X	X
CNC				X	X				X	X	X
Malin-Tesla/Tracy										X	

Source: RIR

The five top Transmission options that can completely or partially mitigate the potential transmission overloads are Options E, G, I, K, and L under all three seasonal conditions. The common facilities that are within these options consist of the C3ET Project and either the Round Mountain- Tesla/Tracy and/or the CNC Project. The next common transmission additions consist of the Gregg-Cottle-Tesla/Tracy.

Similarly, for N-1, leaving out Lines 30, 33, and 48, which are primarily load-serving-related and summarizing the results, the authors show in Table 47:

Table 47: Combined incident of Potential Overloads for N-1

Line #	From Substation	To Substation	Nominal Voltage	Overload Range %	# of Overloads	Options to mitigate Overloads	
						Complete	Partial
Line 6	MALIN	ROUND MT.	500	110-127	10	--	
Line 6	MALIN	ROUND MT.	500	101-120	10	--	
Line 2	ROUND MT.	TABLE MT.	500	101-119	19	K	E, F, G, H, I, J, L
Line 44	AIRPORTW	COTWDWAP	230	133-142	10	--	
Line 26	PANOCHÉ	MCMULLN1	230	123-137	10	B, C, D, E, G, I, L	
Line 31	MCMULLN1	KEARNEY	230	119-137	10	B, C, D, E, G, I, L	
Line 53	OLINDAW	KESWICK	230	118-124	10	--	
Line 50	KESWICK	AIRPORTW	230	116-124	10	--	
Line 32	BULRD_EC	KEARNEY	230	112-129	10	B, C, D, E, G, I, L	
Line 34	MC CALL	HENTAP2	230	111-140	10	B, C, D, E, G, I, L	
Line 39	GATES	MIDWAY	230	100-144	10	I	B, C, D, E, G, L
Line 51	OLINDAW	OLINDA	230	100-137	10	K	E, F, J, L
Line 7	COTWD_E	ROUND MT	230	103-144	9	H, I, J, K, L	E, F, G
Line 45	COTWDWAP	ROUND MT	230	102-153	9	H, I, J, K, L	E, F, G
Line 10	CPVSTA	CORTINA	230	100-118	7	J, K	E, F, I, G, H, L
Line 29	STOREY 1	GREGG	230	101-132	6		G, H, I, J, K, L
Line 23	EIGHT MI	TESLA E	230	100-117	6		G, H, I, J, K, L
Line 20	STAGG-J2	TESLA E	230	100-115	6		G, H, I, J, K, L
Line 52	OLINDAW	COTWDWAP	230	101-118	5	G, H, I, J, K, L	E, F
Line 9	BRNY_FST	PIT 1	230	109-195	3	G, H, I, J, K, L	E, F
Line 8	COTWD_F	BRNY_FST	230	109-193	3	G, H, I, J, K, L	E, F
Line 18	T22_93	FULTON	230	108-176	3	--	
Line 19	LAKEVILLE	T22_93	230	108-174	3	--	
Line 18	T22_93	FULTON	230	103-153	2	--	
Line 17	FULTON	IGNACIO	230	100-144	2	--	

Source: RIR

Mapping the lines that can potentially overload to the instances that the Transmission options can either completely or partially mitigate the overloads, the research team can identify the transmission projects that are common to the most effective transmission options. These are shown (highlighted in green) in Table 48.

Table 48: Transmission Upgrade Breakdown for N-1

Facility Operating Voltage	Transmission Options										
	B	C	D	E	F	G	H	I	J	K	L
Number of 500 kV overloads reduced				1	1	1	1	1	1	1	1
Number of 230 kV overloads reduced	5	5	5	12	7	14	9	14	10	10	15
Total number of overloads reduced	5	5	5	13	8	15	10	15	11	11	16
Transmission Additions											
C3ET Project	X	X	X	X		X		X			X
Gregg-Cottle			X					X			
Cottle-Tesla/Tracy		X	X					X			
Round Mt – Tesla/Tracy						X	X	X	X	X	X
CNC				X	X				X	X	X
Malin-Tesla/Tracy									X		

Source: RIR

The four top Transmission options that can completely or partially mitigate the potential transmission overloads are Options E, G, I, and L. The common facilities that are within these options consist of the C3ET Project and either the Round Mountain- Tesla/Tracy and/or the CNC Project. The next common transmission additions consist of the Gregg-Cottle-Tesla/Tracy.

It should be noted that in Table 46 through Table 48 some of the overloads are only partially mitigated by these Transmission options. In addition, there are potential transmission problems that are affected by the transmission options studied. This list of potential problems is identified and should be investigated by the respective transmission owners as information around future resources develop.

Transmission Ranking Method 2

The second method to rank the transmission options starts by aggregating all of the spring, summer, and fall overload results separated under N-0 and N-1 analysis. The transmission options are ranked from most effective transmission option to consider (ranking of 1) to least effective transmission option. Overloads caused by transmission upgrades were not included in ranking of the transmission options. For example, if a transmission line did not have an overload occur when Option A (generation only) was installed, but resulted in an overload occurring when one of the transmission upgrade options was installed, it is omitted in the transmission options rankings below in Table 49 below.

Table 49: Transmission Option Ranking for N-0

Rank	Option	230 kV Overloads	500 kV Overloads	Total Occurrences	Diff	C3ET	Cottle-Tesla/Tracy Project	Cottle-Gregg	CNC	Round Mt-Tracy/Tesla	Malin-Tracy/Tesla
	A	70	32	102							
1	L	48	20	68	-34	X			X	X	
2	I	50	19	69	-33	X	X	X		X	
3	E	54	16	70	-32	X			X		
3	G	50	20	70	-32	X				X	
4	K	54	19	73	-29				X	X	X
5	J	56	27	83	-19				X	X	
6	B	60	24	84	-18	X					
7	C	61	24	85	-17	X	X				
7	D	61	24	85	-17	X	X	X			
7	H	59	26	85	-17					X	
8	F	64	24	88	-14				X		

Source: RIR

Using the N-0 transmission ranking table as an example, Option A had a total of 102 overload occurrences for spring, summer, and fall for all 10 renewable resource scenarios (Table 25). With transmission Option L upgrades, the total number of overload occurrences has been reduced to 68. A total number of the overload occurrences was computed for the remaining transmission options as well and ranked from fewest to greatest number of overloads. Each transmission option is expanded to show what transmission projects that make up the transmission options. For example, Option L consists of C3ET, CNC, and Round Mt. to Tesla transmission upgrades. This was completed for the subsequent transmission options. By expanding each option, we can better reach a conclusion on which transmission upgrade will have the most priority. Examining the top five ranked lines highlighted, transmission upgrades C3ET and Round Mt. to Tesla both have four instances of occurring most frequently as indicated with a bold X.

Table 50: Transmission Option Ranking for N-1

Rank	Option	230 kV Overloads	500 kV Overloads	Total Occurrences	Diff	C3ET	Cottle-Tesla/Tracy Project	Cottle-Gregg	CNC	Round Mt-Tracy/Tesla	Malin-Tracy/Tesla
	A	314	97	411							
1	L	133	48	181	-230	X			X	X	
2	I	137	49	186	-225	X	X	X		X	
3	G	142	52	194	-217	X				X	
4	K	195	11	206	-205				X	X	X
5	E	199	47	246	-165	X			X		
6	J	197	53	250	-161				X	X	
7	H	206	55	261	-150					X	
8	F	270	55	325	-86				X		
9	D	246	90	336	-75	X	X	X			
10	C	246	91	337	-74	X	X				
11	B	246	92	338	-73	X					

Source: RIR

This process was repeated for the N-1 results. See Table 50. Under N-1, Option A had a total 411 overload occurrences. Similarly to N-0, Option L transmission upgrades had the greatest benefit in reducing the amount of overloads that were caused by only installing renewable generation (Option A). Option I was ranked second in both N-0 and N-1. The remaining transmission options after second place are ranked differently between the N-0 and N-1 results. With each transmission option expanded to display which transmission upgrade occurs most frequently, as with the N-0 results, C3ET and Round Mt. to Tesla transmission upgrades occur four times. This method of ranking concludes that the transmission upgrades that are most crucial when examining the need for transmission upgrades would be C3ET and Round Mt. to Tesla.

Both methods of transmission ranking reached the same result. For both N-0 and N-1, Options L, I, E, G and K alleviated the most overloads. The transmission upgrades that comprised of the transmission options are C3ET and Round Mt. to Tesla project.

As mentioned in Method 1, some of the overloads are only partially mitigated by these Transmission options as indicated in Table 49 and Table 50.

Transmission Ranking Method 3

The third method to rank the transmission options starts by aggregating all of the spring, summer and fall AMWSO (N-0 analysis), and, separately AMWCO (N-1 analysis) developed above . The transmission options are ranked from most effective transmission option to consider (ranking of 1) to least effective transmission option. The ranking for N-0, based on AMWSO, is shown in Table 51 below:

Table 51: Transmission Option Ranking for N-0

Rank	Option	AMWSO	Difference	C3ET	Cottle-Tesla/Tracy	Cottle-Gregg	CNC	Round Mt - Tracy/Tesla	Malin-Tracy/Tesla
	A	14656	--						
1	I	5051	-9605	X	X	X		X	
2	D	6363	-8293	X	X	X			
3	L	8518	-6138	X			X	X	
3	E	8803	-5853	X			X		
4	C	9221	-5435	X	X				
5	B	9272	-5384	X					
6	G	9423	-5233	X				X	
7	K	12661	-1995				X	X	X
7	H	13570	-1086					X	
7	F	13576	-1080				X		
8	J	14349	-307				X	X	

Source: RIR

The ranking of the transmission options for N-0 in this method is slightly different from the last two methods because it also includes the magnitude of the overloads in addition to the number of occurrences. The most beneficial transmission lines are C3ET Project, followed by Round Mt.-Tracy/Tesla 500 kV line and Tracy/Tesla – Cottle 500 kV line.

Similarly, the ranking for N-1, based on AMWCO, is shown in Table below:

Table 52: Transmission Option Ranking for N-1

Rank	Option	AMWCO	Difference	C3ET	Cottle-Tesla/Tracy	Cottle-Gregg	CNC	Round Mt - Tracy/Tesla	Malin-Tracy/Tesla
	A	99596	--						
1	L	45130	-54466	X			X	X	
2	I	45836	-53760	X	X	X		X	
3	G	46886	-52710	X				X	
3	K	50259	-49337				X	X	X
4	J	59572	-40024				X	X	
5	E	64112	-35484	X			X		
6	H	68694	-30902					X	
7	D	72166	-27430	X	X	X			
7	C	73780	-25816	X	X				
7	B	75641	-23955	X					
8	F	75971	-23625					X	

Source: RIR

The ranking of the transmission options for N-1 in this method is similar the last two methods. The most beneficial transmission lines are C3ET Project and the Round Mt.-Tracy/Tesla 500 kV line and the CNC Project.

All three ranking methods produced similar results. The transmission options identified with the most increases in reliability in all three methods are Options E, G, I and L. Based on the

assumptions used across all renewable scenarios studied, the C3ET Project and the Round Mt. – Tracy/Tesla are found to be most beneficial. The CNC Project, the Tracy/Tesla – Cottle and the Cottle – Gregg are also found to be beneficial.

As mentioned in the discussion on Method 1 and Method 2, some of the overloads are only partially mitigated by these transmission options as indicated in Table and Table .

Other Potential Transmission Upgrades

Because the transmission options did not resolve all overloads, these overloads are identified for further studies, if the associated transmission project(s) is selected for implementation. The results of Method 2 are analyzed here. However, the analysis can be used with all three methods.

To identify the top 10 transmission line overloads after implementing the transmission reinforcements in the options, the results from each season was analyzed. The maximum number of transmission line overload occurrences was calculated for each transmission line. Every scenario and transmission option was accounted for spring, summer, and fall. Table 53 below accounts for both N-0 and N-1 overloads that occurred most frequently out of all of the analyses.

Table 53: Top 10 Transmission Line Overloads After the Transmission Options Are Implemented

Ranking	Line #	From Substation	To Substation	Nominal Voltage
1	Line 6	MALIN	ROUND MT	500
2	Line 48	FOLSOM	ORANGEVL	230
3	Line 59	C.COSTA	LONETREE	230
4	Line 30	GREGG	FGRDN T2	230
4	Line 33	HERNDON	FGRDN T1	230
4	Line 44	AIRPORTW	COTWDWAP	230
4	Line 50	KESWICK	AIRPORTW	230
4	Line 53	OLINDAW	KESWICK	230
5	Line 51	OLINDAW	OLINDA	230
6	Line 18	T22_93	FULTON	230

Source: RIR

The top 10 transmission line overload is ranked in **Table 53**. Line 6 is a 500 kV circuit that was the most problematic line overload in the analysis. The remaining 9 of 10 top transmission line overloads are all 230 kV. Line 48 and 59, are ranked second and third most overloaded lines in the analysis. The next five transmission lines, 30, 33, 44, 50, and 53, are tied for fourth. Line 51 and 18 are the fifth and sixth ranked top ten overloads.

Knowing which transmission lines are most problematic when anticipating large-scale deployment of renewable resources will be crucial in maintaining reliability and balancing electrical loads.

Conclusions

Reinforcing access to the transmission grid is essential for large-scale deployment of renewable resources. The existing transmission grid is nearing its maximum capacity. Combined with new renewable resource development being planned in various areas of California, this report offers a methodology for utility transmission planners to adopt a proactive alternative to assess the necessary transmission expansion, which will likely require long lead time. Because a transmission system must meet performance standards over all reasonable adverse system conditions, studies were conducted for three seasonal system conditions. The expectation is that transmission plans developed to meet standards for the more severe system conditions will also meet standards for the less severe conditions.

The transmission options developed or proposed address the effects of large-scale deployment of renewable resources. Potential for overloads on the grid are mitigated with the new transmission options in both normal (non-emergency) and emergency contingency situations. An updated renewable resource database was pooled to create 10 different renewable generation profiles that meet the 2020 33% RPS goal for three separate seasons, 2020 summer peak, 2020 spring peak, and 2020 fall off-peak.

Further, the studies show that the adding 500 kV transfer capability on paths between Round Mountain and Tesla/Tracy Substations and between Midway and Gregg Substations are electrically the most beneficial. Expansion of the 500 kV path north of Round Mountain Substation towards the Pacific Northwest, adding 500 kV transfer capability on paths between Tesla/Tracy, Cottle and Gregg Substations are also found to be beneficial.

The original scope of the RIR Project envisioned that after a prioritized list of transmission expansion projects was developed, there would be follow-on simplified feasibility and cost estimate effort. In particular, that effort would have included an assessment of the technical feasibility (such as availability of space in existing substations) and transmission cost estimates for the implementation of the transmission projects. However, since the 2007 inception of the RIR Project, other efforts have been initiated, including the Renewable Energy Transmission Initiative, the California Transmission Planning Group (CTPG), and more recently, the California ISO's Renewable Energy Transmission Planning Process proposal. CTPG is now developing a California state-wide transmission plan to meet the state's 33% by 2020 Renewable Portfolio Standard (RPS) goal, with a view toward actually implementing transmission system expansions. Therefore, rather than duplicating those other efforts, this final report represents the completion of the RIR Project.

The information and methodology developed through the RIR Project will be turned over to the CTPG and other stakeholders to support their forward-looking analyses.

REFERENCES

- [1] Energy Commission's PIER Intermittency Analysis Project (IAP)
- [2] Strategic Value Assessments (SVA).
- [3] Pacific Gas and Electric Company (PG&E) in conjunction with PIER, took the initiative to implement the RIR project for Northern California
- [4] Studies performed under the Renewable Energy Transmission Initiative (RETI)
- [5] other Energy Commission integration studies

APPENDIX A: COMPLETE LIST OF PROPOSED INJECTION POINTS FOR WIND AREAS (W), SOLAR AREAS (S), AND GEOTHERMAL AREAS (G)

Areas	Bus Number	Name	Nom kV
W1	31000	Humboldt	115 (upgrade to 230)
	30105	Cottonwood	230
W2 (North)	30245	Round Mt.	230
	30005	Round Mt.	500
	30185	Pit 1	230
	40687	Malin	500
W2 (South)	30300	Table Mt.	230
	30015	Table Mt.	500
	30250	Caribou	230
W3	30450	Cortina	230
	30430	Fulton	230
	30460	Vaca Dixon	230
	30030	Vaca Dixon	500
	30495	Stagg	230
W4	30330	Rio Oso	230
	46827	Summit Metering Station	115 (upgrade to 230)
	30500	Bellota	230
	37016	Rancho Seco	230
W5	30624	Tesla	230
	30040	Tesla	500
	30735	Metcalf	230
	30042	Metcalf	500
	30630	Newark	230
W6 (West)	30765	Los Banos	230
	30050	Los Banos	500
	30790	Panoche	230
	30900	Gates	230
	30055	Gates	500
	30873	Helm	230
W6 (East)	30810	Gregg	230
	30800	Wilson	230
	30515	Warnerville	230
W7	34796	Carizzo Plains	115 (upgrade to 230)
	30915	Morro Bay	230
W8/W9	30245	Round Mt.	230
	30005	Round Mt.	500
	30185	Pit 1	230
	40687	Malin	500
W10/W11	30970	Midway	230
	30060	Midway	500
W12	30810	Gregg	230
	30800	Wilson	230
	30515	Warnerville	230

Areas	Bus Number	Bus Name	Nom kV
S1 (North)	30245	Round Mt.	230
	30005	Round Mt.	500
	30185	Pit 1	230
	40687	Malin	500
S1 (South)	30300	Table Mt.	230
	30015	Table Mt.	500
	30250	Caribou	230
S2	30330	Rio Oso	230
	46827	Summit Metering Station	115 (upgrade to 230)
S3/S4/S5/S6/S7/S8	30970	Midway	230
	30060	Midway	500
S9 (West)	30765	Los Banos	230
	30050	Los Banos	500
	30790	Panoche	230
	30900	Gates	230
	30055	Gates	500
	30873	Helm	230
S9 (East)	30810	Gregg	230
	30800	Wilson	230
	30515	Warnerville	230
S10	34796	Carizzo Plains	115 (upgrade to 230)
	30915	Morro Bay	230

Areas	Bus Number	Bus Name	Nom kV
G1/G5/G6/G9 (North)	30245	Round Mt.	230
	30005	Round Mt.	500
	30185	Pit 1	230
	40687	Malin	500
G2	30430	Fulton	230
G3/G4 (South)	30970	Midway	230
	30060	Midway	500
G6 (South)	30300	Table Mt.	230
	30015	Table Mt.	500
	30250	Caribou	230
G7/G8/G9 (South)	30970	Midway	230
	30060	Midway	500

APPENDIX B: SCENARIO MIX BREAKDOWN

Location	Resource	Max MW	Scenario 1 (MW)	Scenario 2 (MW)	Scenario 3 (MW)	Scenario 4 (MW)	Scenario 5 (MW)
Medicine Lake Telephone Flat	GEO	175		175	175	175	175
Geysers	GEO	400	400	400	400	400	400
G-1	GEO	256		200	170		200
G-2	GEO	1,468		270		500	200
G-3-G4	GEO	466	925				450
G-5	GEO	250					
G-6	GEO	1,100		1,200			350
Fire Threat	BIO	132			132	132	132
Urban, Agr, Veg	BIO	363			363	363	363
Solano	HWD	275	275	275	275	275	275
Altamont	HWD	132	132	132	132	132	132
W-1	HWD	2,595			200	500	
W-2	HWD	2,109			200		
W-3	HWD	422			500	300	
W-4	HWD	1,363			500		
W-5	HWD	537			250	400	
W-6/12	HWD	9,225			500	450	
W-7/10/11	HWD	39,756	1,500				
W-8	HWD	2,000					
W-9	HWD	2,000					
Contra Costa	LWD	28		28	28	28	28
Siskiyou	LWD	41		41	41	41	41
Yolo	LWD	3		3	3	3	3
S-1	CSP	9,035			200		
S-2	CSP	887			200		
S-3-S4/5/6	CSP	1,051,410	1,000				
TOTAL			4,304	2,724	4,269	3,699	2,749

Location	Resource	Max MW	Scenario 6 (MW)	Scenario 7 (MW)	Scenario 8 (MW)	Scenario 9 (MW)	Scenario 10 (MW)
Medicine Lake Telephone Flat	GEO	175	175		175		
Geysers	GEO	400	400				
G-1	GEO	256			200	200	
G-2	GEO	1,468				250	140
G-3-G4	GEO	466		600			45
G-5	GEO	250					
G-6	GEO	1,100	350		350		
Fire Threat	BIO	132	132				
Urban, Agr, Veg	BIO	363	363				
Solano	HWD	275	275				
Altamont	HWD	132	132				
W-1	HWD	2,595	200			100	50
W-2	HWD	2,109	150		1,000	2,000	552
W-3	HWD	422	100			280	1,396
W-4	HWD	1,363			500	450	38
W-5	HWD	537				200	241
W-6/12	HWD	9,225					
W-7/10/11	HWD	39,756	700	3,000		1,400	1,824
W-8	HWD	2,000	500		1,000		
W-9	HWD	2,000			1,000		
Contra Costa	LWD	28	28				
Siskiyou	LWD	41	41				
Yolo	LWD	3	3				
S-1	CSP	9,035					
S-2	CSP	887			1,000	250	
S-3-S4/5/6	CSP	1,051,410		2,000		1,000	2,400
TOTAL			4,049	5,600	5,225	6,130	6,686

APPENDIX C: ACRONYM GLOSSARY

AC	Alternating Current
AMWCO	Aggregated Mega-Watt Contingency Overload
AMWSO	Aggregated Mega-Watt Single Overload
APCO	Aggregated Percentage Contingency Overload
BEW	Behnke Erdman and Whitaker
CA	California
California ISO	California Independent System Operator
CAT	Core Analysis Team
CDWR	California Department of Water Resources
Energy Commission	California Energy Commission
CHP	Combined Heat and Power
CNC	
COI	California-Oregon Intertie
CPUC	California Public Utilities Commission
DC	Direct Current
DPC	Davis Power Consultants
EAO	Energy Analysis Office
G	Geothermal
GW	Giga-watt
GWh	Giga-watt hour
HECO	Hawaiian Electric Company
HVAC	High-voltage Alternating Current
HVDC	High-voltage Direct Current
IAP	Intermittency Analysis Project
IOU	Independently Owned Utility
LLNL	Lawrence Livermore National Laboratory
MD	Midway
MVA	Megavolt Ampere
MW	Mega-watt
MWh	Mega-watt hour
NERC	North American Electric Reliability Council
PG&E	Pacific Gas and Electric
PIER	Public Interest Energy Research
POU	Publicly Owned Utility
PV	Photovoltaic
RA	Resource Adequacy
RAS	Remedial Action Scheme
RETI	Renewable Energy Transmission Initiative
RIR	Regional Integration of Renewables
RM	Round Mountain
RPS	Renewable Portfolio Standard
S	Solar
SMUD	Sacramento Municipal Utility District
SPS	Special Protection Scheme
SVA	Strategic Value Assessment
TANC	Transmission Agency of Northern California
TE	Tesla
TM	Table Mountain
W	Wind
WAPA	Western Area Power Administration

kV	Kilo-volts
kWh	Kilo-watt hour

WECC	Western Electricity Coordinating Council
WTLR	Weighted Transmission Loading Relief

**APPENDIX D: RESOURCES IN THE CALIFORNIA ISO
INTERCONNECTION QUEUE
AS OF NOVEMBER 10, 2008**